

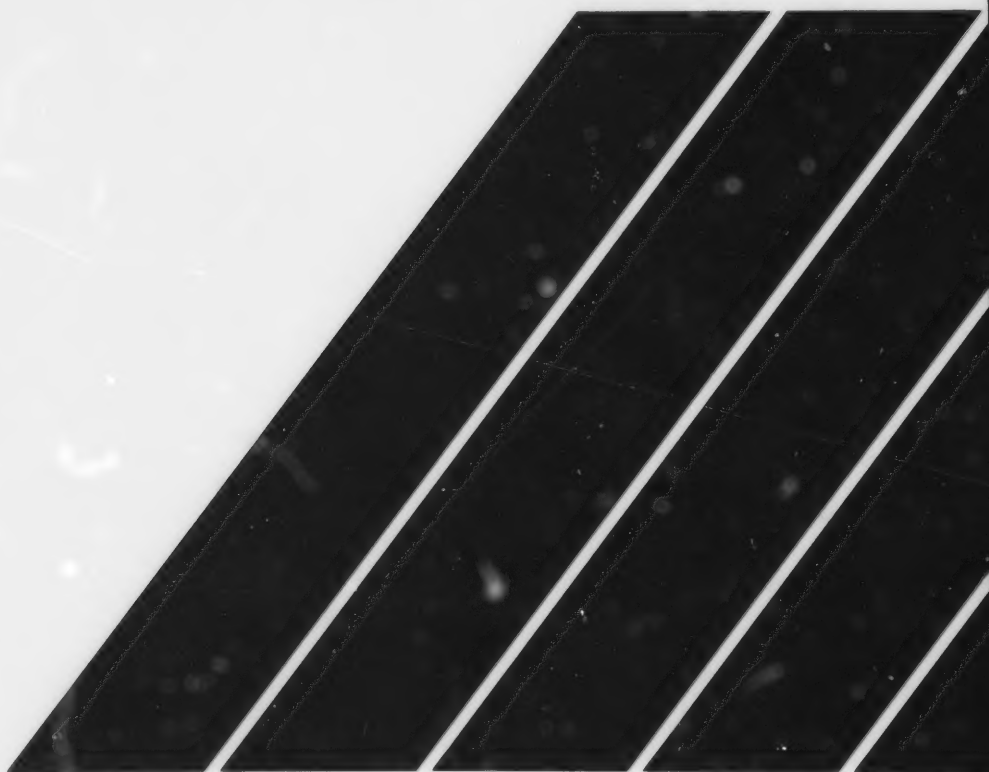
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FLUID FLOW PHENOMENA IN HETEROGENEOUS SYSTEMS

VOLUME 1

**DISPLACEMENT MECHANISMS DURING
GRAVITY ASSISTED IMMISCIBLE GAS INJECTION**

PHASE I

FINAL REPORT

by:

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EXECUTIVE SUMMARY

The Rainbow Basin Carbonate Reefs are extremely heterogeneous reservoirs containing light oil which has been exploited in a variety of ways which include primary depletion, waterflooding (secondary) and hydrocarbon miscible floods (tertiary). It has been recently proposed to use Gravity Assisted Immiscible Gas Injection (GAIGI) for EOR in the same area. The target reservoir is Rainbow Keg River "F" pool which is a vuggy, highly fractured dolomite reef. In order to come up with reasonable production forecasts and recovery under the GAIGI scheme an elaborate study was undertaken. The main objective is to understand multiphase flow phenomena in heterogeneous systems similar to the Rainbow Keg River environment. Another objective is the characterization of the target reservoir in a way that will allow a successful design of the proposed EOR scheme in the field.

This report covers the first phase of this study. It involves flow of three immiscible phases (water, oil, air) in two dimensional (2-D) glass micromodels and in unconsolidated media under ambient conditions. It also involves the development and implementation of techniques for the measurement of wettability characteristics and capillary pressure curves of heterogeneous systems such as the Rainbow Reefs.

GAIGI tests in 2-D micromodels under a variety of wetting conditions for systems of considerably different pore geometries have shown that waterflood sweep efficiency and aspect ratio are the critical parameters for oil recovery. Tests in unconsolidated systems confirmed that during GAIGI an oil bank is formed under water wet, mixed wet or oil wet conditions. The efficiency of the gas injection process increases with decreasing waterflood sweep efficiency.

Wettability, permeability and capillary pressure measurements were performed in a variety of core plugs from two wells. It was found that the rock matrix is predominantly water wet, while the vuggy porosity varies between water wet and oil wet. Vastly different capillary pressure curves were measured. Permeability determination work revealed that large permeability variations exist in the reservoir.

New approaches were presented for the evaluation of the GAIGI process in the centrifuge, coupled with calculation for the determination of capillary pressures in a three phase system. Development work for modeling of the experimental results was initiated. A novel approach that eliminates numerical dispersion problems during the simulation process is presented and results are compared with analytical solutions.

RESUME

Les récifs carbonatés du bassin de l'Ouest canadien sont des réservoirs extrêmement hétérogènes renfermant de l'huile légère qui ont été exploités de diverses façons, incluant le drainage primaire, l'injection d'eau et l'injection d'hydrocarbures miscibles. L'injection de gaz non miscible aidé par la gravité (IGNMAG) a été récemment proposée pour la récupération améliorée de l'huile (RAH) dans la même région. Le réservoir cible était le gisement Rainbow Keg River "F" qui est composé d'un récif dolomitique vacuolaire et fracturé. Afin d'arriver à des prévisions bien fondées pour le recouvrement sous l'effet du plan d'IGNMAG une étude détaillée fut entreprise. L'objectif principal est de comprendre le phénomène de l'écoulement polyphasé dans des systèmes hétérogènes semblables au milieu sédimentaire Rainbow Keg River. Un autre objectif est la caractérisation du réservoir cible de façon à permettre un plan fructueux pour l'implantation de la RAH proposée pour ce champ pétrolifère.

Le présent rapport traite de la première phase de cette étude. Il implique l'écoulement de trois phases non miscibles (eau, huile, air) dans des micros modèles en verre à deux dimensions (2-D) et des milieux non consolidés dans les conditions ambiantes. Il implique aussi le développement et l'implantation de techniques pour mesurer les caractéristiques de mouillabilité et les courbes de pression capillaire de systèmes hétérogènes tels que les récifs Rainbow.

Des essais d'IGNMAG dans des micros modèles à 2-D sous une gamme de conditions mouillantes pour des systèmes dont la géométrie des pores varie considérablement a démontré que le bon rendement de l'injection d'eau et le rapport d'aspect ("aspect ratio") sont les paramètres critiques pour le recouvrement de l'huile. Des essais sur des systèmes non consolidés confirment que durant l'IGNMAG un banc d'huile se forme sous des conditions de mouillage à l'eau, mixte et à l'huile. Le rendement de l'injection de gaz augmente avec la diminution du rendement de l'injection d'eau.

Des mesures de mouillabilité, de perméabilité et de pression capillaire ont été prises sur une variété de bouchons de carottes provenant de deux puits. Il a été observé que la matrice de la roche est surtout mouillée à l'eau, tandis que la porosité vacuolaire varie entre mouillée à l'eau et à l'huile. Des courbes de pression capillaire très différentes ont été mesurées. Des mesures de la perméabilité démontrèrent que de grands écarts de perméabilité existent dans le réservoir.

De nouvelles façons de procéder à l'évaluation du plan d'IGNMAG dans la centrifugeuse ont été présentées, associées avec le calcul pour la détermination des pressions capillaires dans un système à trois phases. Le travail de développement pour le modèle des

résultats expérimentaux à amorcé. Une nouvelle façon de procéder qui élimine les problèmes de dispersion numérique durant la simulation est présenté et les résultats sont comparés avec les solutions analytiques.

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NOMENCLATURE

f	:	partial flow function
$\rightarrow$		
g	:	gravity acceleration vector
k, k_r	:	absolute and relative permeability
L	:	core length, m
N_b	:	Bond Number, dimensionless
$\rightarrow$		
n	:	normal unit vector
p	:	pressure
P_c	:	Capillary Pressure, kPa, psi
Q	:	flow rate
R	:	Distance from the rotational axis to the middle of the core, m
r_p	:	Radius of the largest pore which is entered as the entry pressure is exceeded, m
S	:	saturation
$S^{(n)}$	:	a value of the variable S at n -th time level
δS	:	increment of a variable S
ΔT	:	time step
$\rightarrow$		
u	:	velocity vector

$\vec{u} \cdot \vec{v}$: inner product of vectors $\vec{u}$ and $\vec{v}$

Z : Distance from the inflow end of the core, m

μ : viscosity

λ : transmissibility

$\Delta\rho$: Density difference, kg/m^3

σ : Interfacial tension, dyn/cm , mN/m

ω : rate of rotation, rpm

1.0 INTRODUCTION

1.1 Objectives

The objectives of this work are:

- i) To study GAIGI in heterogeneous systems.
- ii) To visualize the GAIGI flow mechanisms at the pore level using 2-D glass micromodels.
- iii) To assess the wettability of Rainbow Keg River "F" pool.
- iv) To measure the porosity and permeability of heterogeneous, vuggy carbonate reservoir rock.
- v) To identify methods and procedures for the separate characterization of the matrix and vuggy porosity and permeability.
- vi) To assess methods of determining two phase relative permeabilities for heterogeneous systems.

1.2 Literature Survey

1.2.1 Wettability

The wetting of solids by liquids is connected to physical chemistry (wettability), to statistical physics (pinning of the contact angle, wetting transitions, etc.), to long range forces (van der Waals, double layers) and to fluid dynamics (de Gennes, 1985). The effect of wettability on reservoir performance was recognized very early in the enhanced oil recovery literature. Mungan (1964) observed that interfacial tension reduction increased the recovery of waterflooding. This experiment revealed that oil wet cores gave higher oil recoveries than water wet cores. Wettability reversal also gave increased oil recovery.

Surface characteristics have a very important role in the contact angle behavior. Morrow (1975) performed a series of tests in polytetrafluoroethylene tubes, and classified the behavior of capillary rise in various classes. Smooth tubes behave differently than tubes with rough surfaces. The degree of roughness also affects the wetting characteristics. Consequently waterflood recovery is also affected by these surface conditions.

Melrose (1982) presented an interpretation of the mixed wettability characteristics that are present in certain rocks by accounting for the electrostatic repulsive forces that act between the double layers in oil / brine and mineral / brine interfaces. He looked at the stability limits of these thin layers. He estimated lower limits of pore sizes in which thin films will occur. The limiting sizes depend on the salinity of the brine.

Wardlaw (1982) performed multiple displacement experiments in the same pore body - pore throat pair to show that large variations in the viscosity of the displacing phase and large variations of interfacial tensions have only small effects on the amount of non wetting phase trapped in imbibition. Trapping is strongly dependent on the shape of the fluid interface, which is a function of the contact angle and the geometry of the pore. In these experiments the displacement efficiency was higher for conditions of intermediate wettability and least for conditions of strong wettability.

In Morrow *et al.* (1986), the effect of crude oil induced wettability changes on oil recovery is examined. The wettability alteration by the crude oil occurred by crude oil film deposition which was resistant to most cleaners. This oil adhesion on the surface depends on the surface conditions. Cores exposed to Moutray crude oil demonstrated improved microscopic displacement efficiencies and reduction of residual oil over those for water wet systems. Displacement of mineral oil from cores pre-exposed to crude oil was especially efficient. Flow visualization experiments in glass micromodels showed that wettability change induced by crude oil led to much improved displacement of oil from pore bodies with trapping of oil in pore throats. Relative permeabilities to water shifted at lower values than the waterwet systems. This was considered to have favourable effects on mobility control and was thought to be helpful in increased sweep efficiency. Spontaneous imbibition of water demonstrated that the crude oil induced a weakly water wet condition. The capillary numbers for mobilization of residual oil trapped under altered wettability conditions were higher than those for waterwet systems, showing that this type of wetting is unfavourable for tertiary recovery because there is less oil and it is more difficult to mobilize.

Excellent reviews of the effect of wettability in the flow phenomena in porous media have appeared through the years. The most comprehensive of these reviews is probably the one published in a series of papers by Anderson (1986a,b,c, 1987a,b,c). Some of the conclusions of this series of papers is included here.

The behaviour of oil in a waterwet system is very similar to the behavior of water in an oil wet system (Anderson, 1986a). Use of degassed fluids rather than real fluids probably causes an overestimation of the oil wetness. Contact angle measurements made by Chilingar and Yen (1983) suggest that most carbonate reservoirs range from neutrally to oil wet. Their work included 16 carbonate cores from

Alberta. Salathiel (1973) introduced the term mixed wettability for a special type of fractional wettability in which the oil wet surfaces form continuous paths through larger pores. The smaller pores remain water wet and contain no oil. The fact that all of the oil in a mixed wettability core is located in the larger oil wet pores causes a small but finite oil permeability to exist down to very low oil saturations. This in turn permits the drainage of oil during a waterflood to continue until very low oil saturations are reached.

Toluene extraction will alter the wettability and relative permeability of many native state cores (Anderson 1986a). Many of the researchers found that toluene used alone is one of the least effective solvents (Anderson 1986a). However, when combined with other solvents, such as methanol or ethanol, toluene is often very effective. The best solvent was found to be a 50/50 mixture of toluene with methanol containing 1 % NH_4OH . It is possible that the wettability will differ when dead crudes at ambient pressure are used. At the present time, however, it is not known whether the difference is important (Anderson 1986a).

Three quantitative wettability measurements are in use today: contact angle, the Amott method, and the USBM method. The contact angle measures the wettability of crude and brine on a polished mineral surface. It is the best method to use when pure fluids and artificial cores are used. It is also used to examine the effects on wettability of experimental conditions such as pressure, temperature and brine chemistry. The USBM and Amott methods measure the average wettability of core. They are superior to the contact angle method when the wettability of native- or restored-state core is measured. They also must be used to determine whether a core has been cleaned completely. The USBM method appears to be superior to the Amott method, which is insensitive near neutral wettability. A modification of the USBM method allows the calculation of both the USBM and Amott wettability indices (Anderson 1986b).

A large number of qualitative wettability measurement methods are available. The imbibition method is the most widely used because it is fast, does not require any complicated equipment, and gives an idea of the average wettability of the core. The microscope examination method is often used in flow visualization studies. Finally, wettability measurement methods based on relative permeability curves are often used when these data are available (Anderson 1986b).

Two methods have been developed to measure the fractional wettability. The NMR method and the dye adsorption method. Neither method is widely used today. There is no method to determine whether a core has mixed wettability (of the Salathiel type). However, it appears that it may be possible to make such determination by examining the results of a glass slide wettability test, a waterflood of the native-state core with many pore volumes of water, several waterfloods of restored-state cores that were aged with different brine saturations, and imbibition and capillary pressure measurements (Anderson, 1986b).

The Archie saturation exponent, n , is almost independent of the wettability when the brine saturation is sufficiently high that the brine is continuous (Anderson, 1986c). Wettability effects become very important when the brine saturation is lowered. In general, essentially all the brine in a uniformly water wet core remains continuous and electrically conducting as the brine saturation is lowered to the irreducible saturation. The Archie saturation exponent has a value of about 2 in water wet formations and cleaned water wet core. The Archie saturation exponent can reach values of 10 or more in uniformly oil wet core with low brine saturations. This occurs because a portion of the brine is trapped, while additional brine is isolated in dendritic fingers where it cannot contribute to the electrical conductivity. Resistivity increases because the brine cross-sectional conducting area decreases, and the lengths of the conducting paths increase. Unless the reservoir is strongly water wet, the saturation exponent should be measured on native- or restored-state cores. If a clean core is used to measure the saturation exponent and the reservoir is actually oil wet, the interstitial water can be underestimated. Although no definite conclusions can be drawn about the effects of wettability on the formation factor, FR , it is likely that the formation factor is affected by changes in wettability. The electrical behavior of mixed wettability core will probably be different from uniformly oil wet systems because the small pores are water wet (Anderson, 1986c). The Archie saturation exponent will not reach the very high values that can occur in uniformly wetted systems. Instead, it seems reasonable to expect that the electrical behaviour of mixed wettability cores will be similar to water wet ones because the small pores and clay particles are water wet and filled with water in both cases. As the brine saturation in a mixed wettability core is reduced, the water in these areas will remain connected and conduct electricity. This will allow the saturation exponent to behave as it would in a water wet core, remaining constant even at low brine saturations.

The capillary pressure curve depends on the interaction of wettability, pore structure, initial saturation and saturation history. In a uniformly wetted porous medium, pore geometry effects and the extremely rough surfaces of a porous medium make the capillary pressure curve insensitive to wettability for small contact angles (less than about 50° for drainage capillary pressure curves and less than about 20° for spontaneous imbibition capillary pressure curves). When the porous medium has fractional or mixed wettability, both the amount and distribution of the oil wet and water wet surfaces are important in determining the capillary pressure curve, residual saturations and imbibition behaviour. There are two basic types of capillary pressure processes: drainage and imbibition. In a drainage process, the non wetting fluid displaces the wetting fluid, while the reverse occurs for imbibition. Generally, there is hysteresis in capillary pressure as the saturation is varied making drainage and imbibition curves different. The terms spontaneous and forced imbibition (and drainage) are used to discriminate between a phase let to imbibe (drain) without external pressure gradient, and a phase forced to imbibe (drain) when the capillary pressure is decreased (increased) from zero to a large negative (positive) value. In

general (Anderson, 1987a) different residual non-wetting phase saturations will be measured after the spontaneous and forced imbibition curves unless the core is very strongly wetted. The area under the capillary pressure curve is equivalent to the work needed for the capillary saturation to occur. This area is reduced as we move from strongly wet to neutrally wet systems. Another way of stating this is that at any given capillary pressure, the non wetting fluid would be able to enter smaller and smaller pores as the wetness of the system is reduced. In addition, the amount of wetting fluid imbibed during the spontaneous imbibition curve would also decrease as the system becomes more neutrally wet because the driving force is reduced.

With respect to relative permeabilities, Anderson (1987b) states that wettability affects relative permeability by controlling the flow and spatial distribution of fluids in a porous medium. In a uniformly wetted core, the effective oil permeability at a given initial oil saturation decreases as the wettability is varied from water wet to oil wet. In addition, the water relative permeability increases and the oil relative permeability decreases as the core becomes more oil wet. In fractionally wetted sandpacks, where the size of the individual water and oil wet surfaces are on the order of a single pore, relative permeabilities appear to be similar to those in uniformly wetted systems. The water relative permeability increases and the oil relative permeability decreases as the fraction of oil wetted surface increases. In a mixed wettability core, the larger, oil filled pores are oil wet, while the smaller water filled pores are water wet. The continuous oil wet paths in the larger pores change the relative permeability curves when compared with a uniformly or fractionally wetted system, and allow the mixed wettability system to be waterflooded to a very low residual oil saturation by the injection of many pore volumes of water. The most accurate relative permeability measurements are made on native-state core, where the reservoir wettability is preserved. When such core is unavailable, the core should be cleaned and restored. Serious errors can result when measurements are made on core with altered wettability, such as cleaned core or core contaminated with drilling mud surfactants. The effective water permeability of a cleaned core at the residual oil saturation will vary, depending on the effectiveness of the core cleaning method. The wetting phase drainage and imbibition relative permeabilities show very little hysteresis in many strongly wetted systems. However, several unsteady state experiments have shown little hysteresis in the nonwetting phase but significant hysteresis in the wetting phase. In many strongly wetted systems, the wetting-phase relative permeability is primarily a function of its own saturation and is very similar for both two- and three-phase relative permeability measurements.

Finally since wettability controls the flow and spatial distribution of fluids in a porous medium, it affects waterflooding. During the waterflooding of a strongly water wet system, at a moderate oil/water viscosity ratio, a large fraction of the OIP is recovered before breakthrough. After breakthrough, the water/oil production ratio increases rapidly, and little additional oil is produced after breakthrough. During the

waterflood of a strongly oil wet system at a moderate oil/water viscosity ratio, water breakthrough occurs early and most of the oil is recovered after breakthrough. Waterfloods are less efficient in oil wet systems than in water wet systems because more water must be injected to recover the same amount of oil. As the wettability of a system ranges from water wet to oil wet, the breakthrough and economical residual oil saturations increase, so oil recovery decreases. The economical residual oil saturation is lower than the breakthrough saturation and the difference between the two gradually increases, so that there is a longer period of simultaneous oil and water production. Small amounts of oil are produced for a long time after breakthrough. The breakthrough and economic recoveries are dependent on both wettability and oil/water viscosity ratio. A waterflood in an oil wet or intermediate wet core is always less efficient than the waterflood in a water wet core at the same viscosity ratio. The conclusion by Anderson contradicts the earlier work by Meugan (1964). The ultimate residual oil saturation, the saturation after a large number of pore volumes of water are injected, is only weakly dependent on the wettability. It is slightly lower near neutral wettability (higher oil recovery), but changes much less than the breakthrough or economic oil saturations. There is some disagreement on the effects of wettability as a core becomes very strongly water wet compared with moderately water wet systems. All three residual oil saturations are essentially the same because there is little production after water breakthrough, with all the oil trapped in discontinuous globules. However, different experimenters suggest that the residual oil saturation can decrease, remain the same, or increase, depending on such variables as heterogeneity, pore geometry, injection rate and inlet and outlet effects. In fractionally wetted sandpacks, the practical residual oil saturation increase as the fraction of the oil wetted surface increases, and the waterflood behavior lies between the curves for 100% water wet and 100% oil wet sandpacks. In mixed wettability cores the continuous oil wet paths in the larger pores enable a mixed wettability core to be waterflooded to a very low residual oil saturation by the injection of many pore volumes of water. Native or restored state cores must be used for waterflooding.

Fleureau (1989) presented a method for the determination of core wettability which is based on the simultaneous use of contact angles and imbibition measurements, both made on the same slides of rock. The contact angles at immersion and immersion of a brine / oil interface on a stone substrate are derived from the unit displacement works measured by a tensiometric technique during cycles of the plate through the interface. A simplified method is proposed to take into account the surficial porosity and rugosity of real systems. The results obtained with thin plates were compared with those of imbibition tests on small plugs. The results were in general agreement.

Mitchell *et al.* (1990) found that there is a quantitative correlation between the level of nitrogen containing carbonaceous material on the pore surfaces of the cores and the Amott wettability indices. Oil wet cores have a high level of carbon, a high oil wetting index and a correspondingly low water wetting index.

Water wet cores have a low level of carbon, a high water wetting index and a correspondingly low oil wetting index. Cores with intermediate levels of carbon can exhibit either intermediate or mixed wettability. The authors presented a calibration curve which can be used for the prediction of the core wetting state from the pore surface carbon composition. Surface analysis of core can provide information about the diagenesis of the material.

Morrow (1990) provided a review of the effects of wettability on waterflooding. He concluded that systems of intermediate or mixed wettability are quite common as opposed to very strongly water wet systems. The contact angle behavior of crude oil / brine systems falls into two main classes distinguished by either small or large hysteresis. The adhesion of crude oil is strongly dependent on pH. Methods in most general use for measuring the wettability of cores are strongly dependent on capillary pressure. Laboratory tests showed that crude oil - brine - rock systems give optimum oil recovery at neutral wettability. Agreement in results for fresh core with those for restored core provides the best indication that reservoir wettability has been duplicated in the laboratory.

In Hirasaki *et al.* (1990) a wettability evaluation during restored state core analysis is presented. Emphasis was given in core from North Sea. They found that a slight modification of the Amott and USBM procedures could provide a good indication of wettability. The method included cleaning with a series of cleaners followed by aging with crude oil. It was found however, that the restored cores were not as oil wet as the "as received" core state. The authors provided guidelines for wettability measurement, solvent extraction and core restoration. They found that as a system becomes less water wet, the discontinuous, trapped water saturation increases, and the drainage capillary pressure curve crosses the water wet curve and becomes vertical at a water saturation higher than what would be expected for a water wet capillary pressure curve. The area under the imbibition capillary pressure curve increases, and the irreducible or residual oil saturation decreases and can approach zero. In a mixed wet system, some of the oil is retained in the core as a capillary end effect that could be represented by a mixed wet capillary pressure model. After the cores had been cleaned with solvents, little of the oil appeared to be retained as an end effect and most was trapped as a discontinuous phase. They found that the oil-water and air-water primary drainage capillary pressure curves of cleaned cores agree well with the mercury-air curve of an adjacent core. They also found indications that the interior of the cleaned core is water wet, but the exterior surfaces are not water wet. They attributed this phenomenon to wicking of contaminants to the external surfaces where solvents evaporate. They also found that contact time of the solvent with the core is as important as the volume throughput.

The use of crude oil for wettability control of Berea core was addressed also by Buckley *et al.* (1991). Crude oil was used for aging of plugs under a variety of conditions. Variables that affected the wettability

index included the crude oil, temperature of aging, initial water saturation, the aging time and the volume of crude oil with which the core was flushed. Cores with wettability from strongly water wet to neutrally wet could be produced by varying the conditions of crude oil exposure. Aging temperature and initial water saturation have predominant influence on the wettability induced by a given crude oil. Stability of the altered wetting states was found to be reasonable for tests in which the cores were stored for two months in mineral oil. In Wolcott *et al.* (1991) the influences of core-pretreatment, brine saturation, and CO₂-flooding on wettability alteration, organic depositional extent, and site and nature of deposition in Berea sandstone cores were investigated. It was found that CO₂-flooding, KOH-treatment, and brine influenced the wettability of Berea cores. Pyrolysis measurements indicated that a minute quantity of absorbed organic material could produce a significant decrease in water wetness, and that the adsorbed organic material consisted primarily of high molecular weight, polar compounds. SEM and thin-section views showed that organic depositional extent was enhanced by CO₂-flooding and KOH treatment, but was impaired by the presence of brine. Microscopic examination of thin-sections revealed that organic deposits were primarily associated with clay deposits. Some oily residue was found adhering to silica surfaces and lodged in pore throats. There was little correlation between wettability alteration, and the other indicators of organic depositional extent.

Smith *et al.* (1991) tried to predict what fluid/fluid/fluid dispersion morphologies could be expected for dispersions formed before injections and the dispersions formed after injection using phase and wettability studies on bulk phases. They determined the actual morphologies of the dispersions during flow, using videomicroscopic studies of the flow of the dispersions through an etched microvisual cell. They observed three different wettability conditions and three different morphologies of flowing dispersions.

1.2.2 Capillary Pressure

The role of capillary phenomena in the recovery of oil from porous reservoirs has been identified as a very important one since the early forties. The Young Laplace equation is used to describe the relationship between the capillary size, the capillary pressure and the fluid / solid surface interfacial properties. For reservoir cores capillary pressure versus saturation relationships are defined experimentally, using mercury injection, porous plate or centrifuge techniques. Leverett (1941) studied the capillary behavior of porous solids and introduced concepts such as the pendular ring formed by the wetting phase in the contact points of sand grains, the correlation between capillary size and column height, saturation hysteresis exhibited between saturation / de-saturation cycles in a porous medium, the Leverett function, which is a group of fluid and rock properties that corresponds to a capillary pressure, and the fractional flow equation concept which is used for the modeling of two phase flow in porous

media. The terms 'capillary pressure', 'threshold pressure' and 'displacement pressure' were used by Hassler *et al.* (1944) to describe the role of capillarity in oil production. They presented the theory of flow including capillary forces and performed experiments using two and three fluid phase systems. It was later found that surface tension is affected by pressure. This effect was measured for mercury by Hills and Hoiland (1984).

Dombrowski and Brownell (1954) presented a general correlation for the prediction of capillary retention of wetting fluids by porous media. The correlation incorporates both the fluid and rock properties. The so-called Dombrowski - Brownell number is the sum of the Bond number and the capillary number. All three numbers have received considerable attention in the literature. In Morrow and Songkran (1981) the interplay of viscous and buoyancy forces is examined with respect to the trapping of the nonwetting phase and correlations between Bond number and capillary number are derived for sandpacks. Various capillary number relationships for sandstones have been presented by Chatzis and Morrow (1984). The effects of capillary number and its components on waterflood efficiency and oil mobilization are given in Wardlaw (1988). In both references critical values for the capillary number are presented which indicate that up to a certain fluid velocity, the residual oil saturation due to waterflooding is constant.

The end effects and capillary pressure discontinuities which are associated with flow in composite systems is a constant puzzle when dealing with multiphase flow problems. Hinkley and Davis (1986) found that the best contact under drainage conditions and for water wet systems is achieved by simply putting tissue paper between the core pieces. They verified their findings using a microwave scanner. However, they were not able to find any good contact system for oilwet cores.

With respect to heterogeneous media, the capillary pressure curves may have scattered points and end up being very misleading. However, a carefully designed experiment could provide us with details about the heterogeneities within the pore system. This was attempted by Yuan (1989) who performed continuous mercury injection tests at very low rates in heterogeneous systems and was able to extract information about the residual non wetting phase ganglia. He has also presented a simple model for the calculation of final saturations from the experimental data.

The concepts of wetting phase saturation have been put under extensive re-evaluation recently. Many researchers have proved that there is no such thing as "irreducible" phase saturation. More recently Melrose (1989) was able to measure wetting phase saturations in the vicinity of less than 5% wetting phase saturations in Berea sandstone. He has shown that the J-function does not scale when significant liquid saturation fraction consists of films.

Capillary pressure data have been also related to other data such as conductivity data. Differences between data at ambient conditions and reservoir conditions have been pointed out by Soendena *et al.* (1989). Their results indicate that the irreducible water saturations obtained at reservoir conditions are higher than the ones obtained at ambient conditions. Similar observation was made for the resistivity indices. They attributed these changes to a change in the wettability preference. The same topic was addressed by Longeron *et al.* (1989) who found that the resistivity / water saturation law (Archie's law) does not give good correlations for vuggy carbonates. In this case, the resistivity / water saturation plot consisted of two straight line segments in log-log coordinates.

The pore level modeling of capillary pressure phenomena has also received considerable attention in the past. A review along with recent developments is presented in Jerauld and Salter (1990). They focused on the hysteresis between drainage and imbibition and found that the aspect ratio strongly influences the pattern of hysteresis. They also found that the correlation of sizes of neighbouring pores have a significant effect in the shapes of the curves for capillary pressure and relative permeability.

Recently, the capillary forces related to fractures and fractured reservoirs became an attractive topic of research, especially when related to the simulation of dual porosity systems. Horie *et al.* (1988) and Firoozabadi and Hauge (1990) addressed this issue by performing experiments in slabbed Berea columns. They addressed only gravity drainage and they found that, given the appropriate stress, good capillary contact is maintained across fractures. They modelled the capillary pressure in fractures by modifying the Young Laplace equation for a system of cones which are in contact through their tips. Pruess and Tsang (1990) presented also a conceptual and numerical model for multiphase flow in fractures. They conceptualized the void space of real rough-walled rock fractures as a two-dimensional heterogeneous porous medium, characterized by aperture as a function of position in the fracture plane. They had portions of the fracture occupied by the wetting and non-wetting phases according to local capillary pressure and global accessibility criteria. Phase occupancy and permeability are derived by assuming a parallel plate approximation for suitably small subregions in the fracture plane. They used their model to calculate relative permeability functions for the fractured medium.

A topic that has not received any attention since the days of Leverett (1941) was the topic of three phase capillary pressure measurement. It is very important to know the capillary pressure characteristics of the system when three phases, all with hydraulic conductivity, occupy the same pore space. The only recent experimental work related to the measurement of three phase capillary pressure data is given by Lenhard and Parker (1988) for drainage. An experimental apparatus is presented. However that authors always reduce the three phase data to two phase data without ever considering the three phases together.

1.2.3 Gravity Assisted Inert Gas Injection (GAIGI)

Gas injection is the oldest of the fluid injection processes. Recent gas injection applications have been intended to increase the ultimate recovery and can be considered as enhanced oil recovery projects. Gas injection may be either a miscible or an immiscible displacement process. In this report only immiscible gas injection is considered. Of particular interest to this work is the immiscible injection of gas in the carbonate reefs of Western Canada. The primary problems with gas injection in carbonate reservoirs (Torabzadeh *et al.*, 1989) are the high mobility of the displacing fluid and the wide variations in permeability. Much greater control over the injection process must be exercised than is necessary with waterflooding. The benefits obtained by the gas injection are dependent upon horizontal and vertical sweep efficiency of the injection gas. The sweep efficiency depends on the type of porosity system present. In recent years promising substitutes for natural gas in immiscible gas injection schemes were pure nitrogen gas or inert gas mixtures with high nitrogen content. The primary advantage of inert gas is its availability and lower cost. Other advantages include (1) prevention of oil encroachment into the gas cap when gas cap is present, (2) higher recoveries compared to water drive in reservoirs having low permeability, (3) residual inert gas at abandonment rather than saleable natural gas and (4) reliability of the supply. Oil fields that have low oil saturation in either primary or secondary gas cap are prime candidates for improved recovery by gas injection into the gas cap (Torabzadeh *et al.*, 1989). Further shrinkage of oil is reduced by gas injection. Inasmuch as it maintains a relatively high pressure gradient in the oil phase, relative permeability to oil remains high and oil is produced faster and in greater quantity.

Injection of gas for pressure maintenance and subsequent recovery of waterflood residual oil was applied to boost the recovery of the Hawkins field in Texas since the middle seventies (McNabb, 1975). Very recently a number of research groups (including Shell and Exxon) started looking into the potential of immiscible gas injection for EOR.

The use of gravity drainage for oil recovery became the focus of interest for all the major companies, when the exploitation of the North Sea reservoirs started. The paper by Hagoort (1980) discussed the extremely high recoveries that can be achieved by gravity drainage. Hagoort identified the relative permeability to oil as a key factor for the high recoveries. He developed a centrifugal technique for the measurement of the oil relative permeability. In his analysis he used dimensionless numbers, such as the capillary number, Bond number and gravity number and identified regimes for different types of flow.

Considerable insight and a large number of demonstration experiments dealing with the use of gravity assisted immiscible gas injection as a novel EOR process is given in Kantzas *et al.* (1988a,b) and in Chatzis *et al.* (1988). In these references description of the pore level mechanisms are given and

extremely high recoveries of waterflood residual oil are reported for unconsolidated systems. Also high recoveries are reported for Berea sandstone. It was explained that when oil spreads on water, the invasion of gas displaces residual oil from large pores. This oil forms a thin film which becomes thicker as the displacement evolves. An oil bank is finally formed which flows downwards and sweeps the reservoir. This approach extends gas injection strategies to reservoirs which are too shallow for miscible floods. Also it avoids the use of any expensive surfactant systems. A detailed literature survey in GAIGI and its potential is given in Kantzas (1989) and will not be repeated here. However, new contributions as well as papers not included in the aforementioned report will be reviewed, along with the description of the principles of GAIGI. Based on the work of Kantzas *et al.*, (1988a,b) and Chatzis *et al.* (1988), Dullien *et al.* (1990) obtained a patent for the production of residual oil from water wet formations by the application of GAIGI combined with the use of semipermeable membranes. These membranes are built in a way that allows oil and water to be produced through the production zone, while gas remains in the formation. There was no mention on how to apply the membrane technique in the field. Following that, Dullien *et al.* (1991a,b) extended the application of GAIGI to oil wet systems. They also tested systems with vertical bedding. They demonstrated that GAIGI is also feasible in non water wet systems. Oil bank was formed in all cases that the spreading coefficient is positive.

High pressure immiscible and miscible displacement tests were performed by Bailey *et al.* (1985). Analysis of their immiscible displacements indicated that the oil recovery in the presence of brine is a function of interfacial tension and, possibly, flow rate. The immiscible floods were inferior to miscible floods.

Pore level mechanisms of gas propagation in immiscible conditions were also investigated by Danesh *et al.* (1987) for the case of both solution gas drive and gas injection. Thin section type micromodels and North Sea crudes were used. Mechanisms of nucleation and growth of gas bubbles were revealed and compared to the movement of gas during immiscible displacements.

The gravity stable displacement of oil by nitrogen has been studied by Naylor and Frorup (1989), who used water wet sandstones and dead oils. They presented results of secondary and tertiary nitrogen injection experiments. In the secondary recovery experiment, *in situ* residual oil saturations (as measured by a radioactive tracer technique) were as low as 0.15 after 68 days of drainage. In the tertiary experiment, the waterflood residual oil saturation was 0.47. During the tertiary gas flood, an oil bank was observed to develop and the oil saturation decreased to 0.08 after 86 days of gas flooding. Oil relative permeability data have been derived from the in-situ saturation measurements and relative permeabilities down to 10^{-5} were observed.

Experimental results for miscible displacements in a large radial Hele-Shaw cell at a wide range of viscosity ratios were compared with preliminary data from immiscible displacements (Allen and Boger, 1989). Both the experimental data and an analysis of the major forces indicate that immiscible displacement gives a significantly greater sweep efficiency to that obtained for miscible displacement at the same mobility ratio. In particular they concluded that the immiscible displacements resemble miscible displacements at viscosity ratios at least two orders of magnitude less, and therefore they can be considered as considerably more stable.

A Canadian patent was awarded to Gussow (1989) which describes a crestal gas injection protocol for the recovery of oil which is enclosed in traps. These traps are defined as geological formations which are open downwards but have impermeable roof and side walls. According to the patent, gas is injected at the top of the trap and pushes oil and water downward. It seems that the patent covers a lot of the ideas included in GAIGI but fails to explicitly state them. The Gussow method (as it is called in the patent and associated pamphlets) limits the gas injection application for the dome traps.

Yang *et al.* (1990) performed gravity drainage experiments in cylindrical tubes, parallel plate models and Berea sandstone cores. They compared their results with theoretical predictions. They found that gravity drainage velocity of the main body of liquid increases with increasing permeability and the magnitude of the ratio of the liquid density to viscosity. The drainage velocity of the liquid film is mainly affected by the thickness of the film. The drainage velocity of a liquid from above permeability barriers decreases as the height of continuous liquid above the barriers decreases, and as the liquid density to viscosity ratio increases.

Schutle *et al* (1990) presented a new 2-D analytical model for gravity stable gas drives or water drives. The model establishes a link between diffusive flow and segregated flow. It predicts the tilt angle and velocity of the injectant/oil interface and iso-saturation lines in the invaded zone for any saturation in between fully segregated and fully diffusive along dip flow. However the model disregards the capillary pressure effects. Good agreement between the model and numerical simulation has been achieved.

Deo and Deans (1990) discussed the potential of water driven CO₂ floods. They were particularly interested in modeling the multiple phases which may form and the number of liquid phases (up to two) that may be trapped by the passing water front. As a result, they modified a general theory of multicomponent, multiphase flow in porous media, so that it could be applied to flow reversal problems. They conducted experiments in a high pressure core flooding apparatus. They performed single brine injection production tests to determine the residual saturation of the carbonic phase after the CO₂ flood. The determined saturation was in good agreement with the saturation established by mass balance. The

method of Deo and Deans (if it can be extended in the field) could be potentially used for the determination of residual saturations past GAIGI.

In Hara and Christman (1990) cyclic immiscible CO₂ huff and puff gave more than 5% pore volume incremental recovery as opposed to brine imbibition. They successfully modelled their results and found that the measured liquid diffusion rate in diatomite?? was consistent with the observed rate of oil production with immiscible CO₂. They also observed that the majority of hydrocarbon was produced as a lower liquid phase, not a vapor. They also concluded that CO₂ can effectively recover oil even when a drive process is not practical.

Application of GAIGI was applied in the recovery of heavy oil reservoir with bottom water by Islam and Chakma (1990). Electromagnetic heating, applied in the production wells will assist the recovery further through oil viscosity reduction. They performed scaled model studies that showed that up to 77% of the oil in place may be recovered even in the presence of a bottom water zone which is as thick as the oil zone.

The presence of three flowing phases in the vicinity of the production well during GAIGI requires appropriate treatment of relative permeabilities. This is the objective of the work by Wardlaw (1990), which is still ongoing. However, Wardlaw's work is more focused towards the AWACT technology and its applications. The central idea is that injection of gas near the production end and then production of fluids will lead to trapping of gas in large pores and modify the relative permeability curves towards increasing liquid effective permeabilities. The concept is currently tested for optimization of conformance in heavy oil applications. In Foulser *et al.* (1990) the concept of relative permeabilities for the gravity stable displacement of waterflood residual oil by gas is presented. They undertook a theoretical and core flooding study of the oil relative permeability. They found that permeabilities generally vary with the cube of the mobile oil saturation. Also the Corey coefficient of 3 is consistent with film drainage. Oil immobilized by the capillary end effect manifested itself as a higher Corey exponent. Multiplicative coefficients were found to be lower than expected and increased from the top to the bottom of the core. Foulser (1990) also presented an analytical investigation of gravity stabilized gas injection using the method of characteristics. He was able to explain compositional effects in the gravity stabilized gas displacement. Effects of rate were studied in Foulser *et al.* (1991).

More recent work includes simulation studies of off-shore tertiary gas injection (Roberts and Hulbert, 1991). According to this study, a typical North Sea tertiary gas injection project is optimized by completing the production wells within the water column, and producing the oil by a reverse coning technique. A semi-analytic coning model was created by the authors for the study of single isolated well

systems. Frorup *et al.* (1991) tried also to simulate gravity stable immiscible nitrogen displacement of black oil using a compositional simulator. They found that at high pressures the Gravity Number becomes more unfavourable, but more effective stripping of the oil phase light and intermediate components takes place in the gas phase.

Oren and Pinczewski (1991) extended the work of Kantzas *et al.* (1988a,b) and Chatzis *et al.* (1988) looking at the thickness of the oil films under horizontal immiscible gas injection at residual oil conditions. They performed experiments in 2-D glass micromodels and theoretical analysis using thermodynamics of film flow coupled with finite element modeling. They concluded that flow of both oil and water is important in determining the displacement efficiency of waterflood residual oil by gas flooding for positive spreading systems under strongly water wetting conditions. Computation of film disjoining pressures show that the stability of experimentally observed water and oil films in glass micromodels is due to ionic-electrostatic and van der Waals interactions respectively. The augmented Young Laplace equation provides realistic estimates of observed oil and water film thicknesses. Computation of the velocity fields in the film profiles determined from the augmented Young Laplace equation provide realistic estimates of the conductivity of thin films in glass micromodels.

With respect to field applications, crestal gas injection has been used extensively in the Maaddud field in Bahrain (Murty *et al.*, 1987). The recovery efficiency of the gas drive/gravity drainage mechanism is expected to reach 41% OOIP as opposed to 25% OOIP by natural water drive. In another zone of the same reservoir, crestal gas injection was considered responsible for increase in reservoir pressure, halting of gas cap shrinkage, decreasing of water cuts and stabilization of daily oil production rates (Murty and Al-Khayat, 1989). The Yates field in Texas has been also a target for gas flooding experiments (Christiansen, 1990). In particular pressure maintenance by gas injection in the East side of the Yates field began since 1976. Gas injection experiments in core from the Yates field showed that injection of CO₂ will give recoveries that are 6% to 11% OOIP greater than those of gas-cap gas. Christiansen (1990) concluded that the incremental recovery is due to oil swelling and viscosity and gas/oil interfacial tension reduction. The Oseberg field is also produced through gas injection (Skattum, 1989). In this particular field it was decided to proceed with gas injection instead of the waterflood. This may not be the optimum way of recovery however, since laboratory data (e.g. Naylor and Frorup, 1989) indicate that gas injection following waterflood is more effective than gasflood or waterflood alone. A number of interesting observations have been reported by Denoyelle *et al.* (1986) for the Coulommies-Vaucourtois field in France. The field was near abandonment when an injection well was drilled between four existing production wells. CO₂ was injected followed by N₂ injection for a period of six months. Two and a half months after CO₂ was first injected, gas broke through into a well located far outside the pattern area. Shortly afterwards, a producing well of the pattern showed a four fold oil production increase as gas

broke through. The three other wells exhibited smoother responses, with production of minute quantities of gas. Significant water oil ratio decreases and oil production increases were observed. A geological model was developed to try and model the flow patterns of the various fluids. The incremental recovery of oil was 14,000 standard cubic feet per incremental barrel of oil.

1.2.4 Use of the centrifuge for core analysis

We have decided to make use of the centrifuge technology for the measurement of wettability, capillary pressure and relative permeability characteristics of porous media. We were driven to this decision because of the technical merits in the accurate determination of wettability and capillary pressure characteristics as well by the apparent cost, speed and efficiency benefits associated with the centrifuge technology as opposed to other currently used core analysis techniques. The use of the centrifuge for the measurement of capillary pressure has been proposed by Hassler and Brunner (1945). They described an apparatus and method to determine capillary pressures and saturations using small core samples in a centrifuge. They concluded that the centrifuge method of measuring capillary pressure suffers from some disadvantages, of which perhaps the greatest is the limitation to a single branch of the hysteresis loop and the fact that the data must be smoothed before the capillary pressures are calculated. They found a weak dependence of capillary pressure on permeability but no dependence on porosity.

Marx (1956) provided a method for predicting the complete gravity drainage characteristics of arbitrary long columns from centrifuge measurements on reconstituted core samples. He claimed that oil residuals corresponding to hundreds of years of normal gravity depletion can be obtained in a few hours on the centrifuge. He also claimed that model and prototype will have the same proportion of capillary retention if the ratio of heights of prototype to model is inversely proportional to the ratio of the gravitational accelerations of prototype to model. Similarly, the scaling of the time of model to prototype is equal to the square power of the ratio as acceleration of model to prototype. However, this does not make sense, unless the units in field and model are different. The author also discusses the subject of representative sampling and its effects in an accurate prediction.

Hoffman (1963) proposed the use of a slowly accelerated centrifuge method for the measurement of capillary pressures. He also proposed an analytic method for the conversion of the data from the centrifuge experiment to capillary pressure. This method had an error pointed out by Luffel, which was incorporated in a corrected numerical approach by Hoffman. However, probably the most intriguing application of centrifuge technology since the original Hassler and Brunner paper was the algorithm presented by Szabo (1974) for the measurement of imbibition using the centrifuge. It is the only method

in the literature by which the imbibition can be measured in a descending positive capillary pressure. This is done by a special design of centrifuge cups. The same author also proposed a "quick" method for the measurement for capillary pressures by testing a stacked core. This technique was adopted by Golaz and Bentsen (1980) who developed a mathematical model for data analysis on multi-slice cores.

The use of parametric techniques for the determination of capillary pressures from centrifuge data was studied by Bentsen (1977). He published two parameter estimation methods for handling centrifuge data. Out of the two methods, he suggested the simpler approximation method for data generation.

Capillary pressure measurements combined by epoxy solidification techniques and followed by imaging of wetting and nonwetting phases were presented by Wunderlich (1985). He was the first to identify that the boundary condition of zero invading phase saturation at the core outlet is not always valid. Although he did not quantify this statement it was later proved (Melrose 1990; O'Meara *et al.* 1990) that the breakdown of this boundary condition is not a restraint in the accuracy of the Hassler and Brunner method.

O'Meara and Lease (1983) and O'Meara and Crump (1985) presented a complete method for the simultaneous measurement of capillary pressures and relative permeabilities in a single experiment using the centrifuge. They have included the design of the experimental apparatus and all the setup for the computer models that accompany the experiment. They considered the drainage case, postulating that for forced imbibition all the information is obtained in a single step rather than a multistep experiment. The idea is to history match the production effluent data and estimate the parameters that compose some given capillary pressure and relative permeability functions. They recommend using heat-shrink tubes to confine the direction of flow to one dimension.

During waterflooding care must be taken so that the capillary number is low enough so that residual oil mobilization is not taking place. Similar precautions have to be taken when the centrifuge is used. A method for calculating the imbibition capillary pressure that accounts for mobilization of residual oil (or capillary de-saturation, or stripping) is given in King *et al.* (1986). The analysis follows two different functions, one for imbibition similar to the Hassler and Brunner method and a second for capillary de-saturation which is used after a critical Bond number is exceeded. The value for the critical Bond number is 10^{-5} . The authors tested Berea and Prudoe Bay cores. They found that, by monitoring the knee on the residual oil saturation vs Bond number curve, there is no unique correlation between Bond number and capillary number.

Bond number conditions for stripping of the wetting phase during drainage is given by Omoregie (1986). He used the Dombrowski and Boewnell (1954) number which is the sum of the Bond number and the capillary number. He also compared different capillary measurement techniques and identified factors that affect their equivalence. These factors are Bond number, clay alteration by sample drying, wettability, equilibration, sample orientation and overburden pressure. He also provided guidelines for the preparation and analysis of a variety of samples.

O'Meara *et al.* (1988a,b) addressed two issues related to the centrifuge measurements of capillary pressure; the outflow boundary condition and cavitation. With respect to the outflow boundary conditions they argued that with proper choice of end piece to support the core sample, the boundary condition is valid in practically all circumstances. They showed that if the end-piece is wetted by the produced fluid, the capillary pressure can be altered significantly. They recommended that if water is the displaced phase, a Teflon end piece should be used instead of a rubber one. They also calculated a critical Bond number that is required in order to meet the 100 % liquid saturation in the outflow. The expression used for the Bond number is

$$N_b = \frac{\Delta \rho \omega^2 R_p^2}{\sigma}$$

which is different from the term used by others such as in King *et al.* (1986) because the radius of the largest pore that is entered at the entry pressure is used instead of the permeability.

$$N_b = \frac{\Delta \rho K r \omega^2}{\sigma}$$

However, it must be noted that the breakdown of the 100% displaced phase saturation boundary condition does not necessarily lead to significant error in the capillary pressure curve. Another very interesting formula is the definition of the capillary pressure given by

$$P_c = P_g \left[1 - \left(1 - \frac{L}{2R} \right) Z - \left(\frac{L}{2R} \right) Z^2 \right]$$

with

$$P_g = \omega_j^2 R L \Delta \rho$$

According to this formula $z=0$ at the inflow, where invading phase enters, and $z=1$ at the outflow end where $P_c=0$. The authors also used a series of recommendations for minimization of errors related to the measurement of capillary pressures. They recommend cleaning of cores, particularly dolomites, with pyridine on top of the conventional chloroform/methanol cleaning (a recommendation that contradicts information by Anderson (1986a,b,c)). They suggest the use of jackets for the core plugs. They also suggest that the effect of a pendant drop in altering the point of zero capillary pressure is not significant. With respect to cavitation they argued that experiments in one atmosphere could be suspect of cavitation. Theoretical arguments showed that cavitation should not occur in water wet rocks when the capillary entry pressure is less than three atmospheres. An experiment showed no evidence of cavitation in rocks with capillary entry pressure of 50 psi.

Comparative studies between different numerical and parametric methods for the calculation of capillary pressure curves from the centrifuge are given in Ruth and Wong (1988, 1990) and Ruth *et al.* (1989). The authors used up to six different techniques for the comparison of the same set of capillary pressure data. All the different approaches have been compiled in a computer package, which was purchased by NHRC. In all three publications it is stressed to use more than one method in order to ensure proper interpretation of the results. Each method performed best under a different set of conditions. However, it must be noted that all methods agreed reasonably well. It is also important to note that the original Hassler Brunner method applies remarkably well in most of the examined cases.

Hawkins and Bouchard (1989) discussed the reservoir engineering implications of capillary pressure and relative permeability hysteresis. Hysteresis was observed in centrifuge experiments, which is different from the hysteresis observed in the traditional methods using porous plates. They concluded that because of cycle dependent hysteresis, first cycle waterflood relative permeability data should be used for engineering waterfloods. However, because of flooding phase dependent hysteresis, second cycle oilflood relative permeability data should be used to simulate the oil bank developed during tertiary EOR processes. The effect of cycle has to be taken into account if wettability information is inferred from relative permeability data. Cycle dependent hysteresis needs to be considered when conducting native-state core analysis. If cores are cut with a water based mud, cut from a waterflooded zone, or core samples are brine flushed in the laboratory, it is not possible to obtain the necessary first cycle waterflood data.

The topic of hysteresis was also discussed in Honarpour *et al.* (1990). They found that the primary effect of cycle dependent hysteresis for the samples tested was a reduction in the wettability index for successive drainage and imbibition cycles.

King *et al.* (1990) reviewed the methods for obtaining capillary pressure from equilibrium centrifuge data. They presented an exact solution and compared it with the approximate methods in the literature. Their apparatus can monitor six cores for up to each second, with 0.004 cm^3 precision. They proposed one day stages and ten stage experiments per set of plugs. They have performed a three week decay study and shown that a stretched exponential, with a stretch parameter of 0.77 is effective in extrapolating one day experimental results to at least ten day interval. They have also presented two parameter estimation procedures for the determination of relative permeabilities.

Another method for the estimation of capillary pressure and relative permeability functions from centrifuge experiments is given by Nordtvedt *et al.* (1990). The authors chose to represent the unknown function with B-splines. Then they used a regression based procedure to select the number of knots and coefficient values. Glotin *et al.* (1990) have also presented an analytical technique for the analysis and interpretation of centrifuge data. They found quite good agreement between centrifuge mercury injection (drainage) and waterflooding (imbibition). Munkvold and Torsaeter (1990) used the single step Hagoort's method (1980) to generate the relative permeability of the displaced phase and a multi speed procedure to get capillary pressure data. They found that the Bond and capillary pressure numbers have to be kept in the same order of magnitude during the experiments. They observed that the valid data range for a centrifuge experiment is usually larger than for an unsteady state relative permeability experiment because the end point saturation is only dependent on the rotational speed used, and not on viscous fingering effects. They also observed that, according to the centrifuge measurements, the oil relative permeability is rate dependant near residual oil saturation.

The low wetting phase saturation measurements using a high speed centrifuge technique were evaluated by Melrose and Mallinson (1990). They performed air/n-decane drainage experiments using both Berea and reservoir plugs. They confirmed that there is a linear relationship between $\log P_c$ and $\log \langle S_w \rangle$ over the average saturation range of 30 % down to 10 %.

2.0 EXPERIMENTAL WORK

2.1 General

Four series of experiments are presented in this report. First, the series of micromodel tests are discussed. Some parts of the micromodel visualizations were recorded in a video tape. The analysis of the data from the centrifuge work follows, including wettability characterization of plugs from the Rainbow Keg River "F" Pool, Berea sandstone and Baker dolomite, including an attempt to duplicate the gas injection protocol in the centrifuge. The attempt was considered successful provided consistency using the Bond number analysis is achieved. Three phase capillary pressure data are presented. The third set of experiments includes the work in glass bead and sand columns. Since one of the most urgent questions to be answered was the effect of wettability on recovery, a large number of tests were performed in micromodels and columns which were treated oil wet through use of hydrophobic agents. In particular, the chemical Aquasil was used for treatment of glass micromodels, glass beads and sand alike. The coating solution is 1% solution in distilled water. The samples were flooded with the solution and they were let to soak for 20-30 min. The soaking step was followed by a drying step in the oven. The drying period varied from about an hour for the glass micromodels to overnight for the sandpacks at approximately 85°C.

2.2 Micromodel Studies

Nine micromodel tests were performed to date. The four micromodels used were coded H2, D2, D1 and S1 respectively. The summary of all the experiments and the corresponding results are tabulated in Table 1. The experimental apparatus is shown in Figures 1 to 3. In all cases the micromodel was placed in the vertical position. A syringe pump was connected for fluid injection from the top (oil injection, Figure 1) or the bottom (water injection, Figure 2) while the production rates and volumes were monitored through the flow of fluids in a capillary tube mounted on a ruler and connected at the other end of the micromodel (bottom for the oil injection, Figure 1, or top for the water injection, Figure 2). The gas injection setup is shown in Figure 3. Atmospheric air was allowed to enter the top of the micromodel by adjusting the level of a leveling bottle connected in series with the flow rate measuring device at the production end. A colour video camera was used to video record all the experiments. The original video tapes are stored in our laboratory. An edited summary version has been distributed to the partners. Photographs of the four micromodels used are given in Figures 4 to 7. Figure 4 shows micromodel H2 which is a heterogeneous model with large pore bodies of parallel-piped shapes which are connected through smaller pore throats. Micromodel D2 is a vuggy system, where large vugs are connected through smaller pores to form a heterogeneous but relatively permeable system. Micromodel D1 is

similar to the micromodel D2 but the vuggy system is also surrounded by a low porosity low permeability matrix. This is the most typical double porosity micromodel of the ones used. Finally S1 is a homogeneous micromodel of a simple square pattern.

The first experiment was performed on the micromodel H2. The micromodel was water wet and it was waterflooded to residual oil saturation prior to gas injection. The gas injection was performed in a stepwise manner by reducing the pressure in the micromodel through lowering the leveling bottle in 0.5-1.5 cm intervals. The time interval was kept long enough until there was no fluid movement in the capillary tube. The minimum time interval was eight hours. The overall incremental recovery after gas injection was 22.5% PV. The second experiment was also performed in micromodel H2 under water wet conditions the difference being the lower liquid flow rates. Similar recovery of oil was observed (20.6% PV). The third experiment was performed in micromodel D2. The experiment was run under water wet conditions and the gas injection was done in a stepwise manner. The incremental recovery from the gas injection was 11.5% PV. The same micromodel, under the same wettability conditions but in a single step gas injection scenario gave only 8.4% incremental recovery after gas injection (experiment #4). This test was performed to provide us with an indication of rate effects in the overall recovery. The single step test involves significantly higher gas pore velocities and it is expected to have a detrimental effect in the overall efficiency of the process. The same micromodel was treated oil wet and a single step gas injection experiment was performed. In this case the recovery due to the injection of gas was significantly lower (3.5% PV). However, the waterflood recovery was significantly higher than the previous two experiments (61.7% PV as opposed to 46.3% PV and 41% PV respectively). The sixth experiment was performed in model D1, under water wet conditions and the stepwise gas injection protocol. The incremental recovery after waterflooding was 29.2% PV. Micromodel S1 was the model used for the next three experiments. In the first two cases, the micromodel was treated oil wet. Gas was injected after waterflooding in a single step mode. In the first case (experiment #7) the incremental recovery from gas injection was 0.0 % PV at a waterflooding efficiency of 62.4% PV. In the second case (experiment #8) the incremental recovery of the gas injection was 1.1% PV at a waterflood efficiency of 53.1% PV. Finally, in the water wet case, there was no incremental recovery after gas injection but there was only 5.7% of the pore volume oil left in the micromodel after the waterflood.

It should be noted that although every effort was taken to collect accurate data for the recovery of fluids in the micromodels, these results should be taken with caution. The two-dimensional nature of the micromodels is by itself a limiting case in the context of the lack of 3-D connectivity in the pore space. Moreover, end effects are quite extreme and the overall calculations are affected by the end effect related volumes. From the mechanistic point of view, it was observed that an oil bank is created in most cases (all the water wet and the oil wet examples where the amount of oil was appreciable). This oil bank

propagated downwards. However, in the heterogeneous models, the presence of high permeability streaks was the cause of long gas fingers. In order for the oil bank to "catch-up" with the front, the injection rates had to be kept very slow. In more than one occasion (experiments #1 and #6) the oil bank was created and moved downwards only to stop right before the production end where the gas bypassed it and broke through a couple of large pore bodies. In these cases the recovery of oil past waterflooding was deceptively low. In the case of the dual porosity micromodel D1 the sweep in the low porosity matrix was extremely slow but it DID occur. There was a high permeability streak at the one end of the micromodel which prevented a better sweep. These tests can be used as an initial indication of the coning problems which are anticipated in the real reservoir. Good sweep efficiency can be seriously compromised if there is even one high permeability streak close to the wellbore.

In the case of the oil wet tests, the recovery of oil by gas injection was considerably lower than in the corresponding water wet cases. The waterflood recovery was considerably higher. This reversed behaviour is mainly due to the different distribution of the residual oil after waterflood. In the water wet case, the oil remains trapped in the larger pore bodies where the gas is expected to invade first. On the contrary, in the oil wet case the trapped oil remains in the smaller pore bodies and in the pore throats which are not invaded by the gas until the capillary pressure reaches a considerably higher threshold value. This capillarity driven reversal in behaviour has a detrimental effect in the recovery process. However, since the oil remains less dense than the water, an oil bank will be formed if there is more oil than the connate oil.

Production characteristics for the various micromodel experiments are given in Figures 8 to 20. In the case of gas injection, only the total amount of liquids was monitored as a function of time. The overall oil production was calculated after the completion of the experiment. From the flow visualization and the video recording, it was shown that only water was produced until the oil bank reached the production end. Oil was not mobilized ahead of the oil bank since the capillary number conditions are extremely low. The gas drainage for the first experiment is shown in Figure 8. Please note that the liquid production responds in the same stepwise manner as the gas injection protocol. The tails of each injection step should correspond to gravity drainage through pore wedges. The waterflood curve and the gas injection curve for experiment #2 is given in Figures 9 and 10 respectively. The waterflood curve is a typical constant rate curve (straight line), while the gas injection curve is a multistep production curve. Similar is the behaviour in experiment #3 (code D#2A) where the constant pressure intervals are clearly identified. The waterflood of micromodel D#2B is shown in Figure 13 followed by the waterflood curve for the oil wet equivalent (micromodel D#2C, Figure 14). The production curve for single step gas injections was not recorded because the operator was fully occupied with the video recording. The waterflood and gas injection curves for micromodel D#1A are shown in Figures 15 and 16. It was very interesting to observe

how the matrix emptied a few weeks after the oil/gas interface has bypassed a given level in the micromodel. In an effort to quantify this slow drainage the rate of drainage was plotted for this experiment (Figure 17). The high rate peaks correspond to the initial flow response to each pressure change. The very slow tails are the drainage through pore wedges and the matrix. Further work is needed in order to quantify the contribution of this low rate drainage in the overall recovery. The last three figures of this session (Figures 18, 19 and 20) are depicting the waterflood curves for the last three tests (micromodel S1). Since the gas was injected in a single step mode, no gas production curves were obtained.

2.3 Centrifuge Work

A considerable part of the presented work was related to the wettability characterization of plugs from the Rainbow Keg River "F" Pool. Since the combined Amott-USBM test was decided to be the evaluation technique, a large number of centrifuge tests were performed. The Beckman L8-55 M/P Ultracentrifuge was used and capillary pressure data were collected at the same time. A computer program called PORCAP was purchased from Prof. Doug Ruth, University of Manitoba, for the calculation of the capillary pressure curves using six different algorithms. The selection of the appropriate model was based on the minimum value of the estimated error between model and real data. Eleven reservoir plugs were tested from two wells, namely 9-28-108-7W6M (7) and 6-6-109-7W6M (4). Three of the eleven plugs were aged after cleaning and were tested again in order to compare the results between preserved and restored core samples. In addition to the reservoir plugs, a large number of Berea sandstone and Baker dolomite plugs were also tested. These additional plugs were used in order for our crew to debug operational problems and set the experimental process. A number of additional tests on reservoir plugs were performed in Core Laboratories. Some comparisons are presented. It was decided to perform the centrifuge tests at reservoir temperature. The service laboratory performed their tests at room temperature. It was felt that heavy hydrocarbon residues would be a lot more mobile and they would contribute more to the wettability assessment. Another thing that was attempted, was the injection of air after the residual oil saturation was reached. This was done in an effort to test whether the centrifuge could be used for gravity assisted immiscible gas injection evaluation tests. At this time some first results are presented. The results were interpreted using a Bond number and capillary number analysis to establish whether the gas injection was performed in a gravity stable manner or not. In all twenty different plugs are analyzed in this report.

The combined Amott USBM test consists of measuring volumes of imbibition and drainage under both static (spontaneous) and dynamic (forced) conditions. The Amott method, in particular, consists of immersing the sample at initial or at residual saturation under the displacing fluids and measuring the final

displaced volume at atmospheric pressure. The sample is then placed in the centrifuge and the volume of imbibition due to dynamic displacement under centrifugal forces is measured. However, when combining Amott and USBM methods, the incremental imbibition at increasing rotational speeds are also measured. These included measuring volumes at 800, 1100, 1500, 2500, 4000, and 6000 RPM which were selected based on past experience with this type of core. Speeds beyond 6000 RPM were avoided due to the very fragile nature of the core, since experience has proven to cause breakage of the sample.

The starting point for all samples for the Amott USBM tests was the irreducible water saturation. However, for the majority of the preserved Rainbow samples, an additional drainage curve is provided which is the result of placing the sample in the centrifuge and performing a forced drainage from the initial water saturation after the sample was degassed under brine.

An example of the Amott USBM testing process for the preserved samples from "F" pool would be as follows. The sample is first brought to irreducible water saturation by first evacuating sample under formation brine to remove gas, and then spinning at 6000 RPM for 6 to 8 hours under oil to remove mobile brine. Once at irreducible water, the sample is immersed under brine in the especially designed Amott cups to measure the spontaneous imbibition of water. Volume stabilization typically takes about 5 hours once fluid temperature has stabilized.

Next the sample is placed in the centrifuge under brine and the incremental oil displaced is measured from 800 RPM to 6000 RPM in the series of steps noted above. It should be noted that the centrifuge is never stopped between increasing speeds. Volume readings are taken with the aid of a strobe light while sample is in rotation.

The same process is repeated under drainage condition in which the displacing phase is the displaced phase and vice versa.

The Amott index to oil is calculated as the ratio of the spontaneous volume of the oil imbibed (oil is the displacing phase) to the total volume of oil imbibed (spontaneous plus forced). The Amott index to water is calculated similarly, however, during water imbibition. The USBM index is measured by generating the capillary pressure curve for each case and determining the area under each curve. The logarithmic ratio of the two areas is the USBM index. Positive USBM indicates water wet.

Eleven plugs were cut horizontally from preserved core from RKR "F" pool. The properties of these plugs are tabulated in Table 2. It can be seen that a relatively wide range of porosities (6 % - 15 %) and air permeabilities (2.0 mD - 2400 mD) were examined. The location and dimensions of each plug are shown

in Table 3. The Amott USBM results for the eleven plugs are shown in Table 4. The Amott index to water is fairly consistent (0.3 - 0.6) and the Amott index to oil is similar (0.3 - 0.75). The USBM index is positive in all cases but two and varies between -0.4 and 1.17. All tests (including the spontaneous imbibition of both liquids) were performed at 87°C. The measured wettability numbers suggest a water wet matrix surrounding vugs of mixed wettability. However, since the vugs need to be accessed through a path of similar wettability for spontaneous imbibition to occur, it is concluded that mixed wettability paths exist throughout the core. It should be noted that the vugs which were opened to surface as a result of coring and plug drilling, were filled with Teflon tape, in order to minimize the error that could otherwise be introduced in the spontaneous stage of the test.

Table 5 presents the fluid saturations at various points of the Amott USBM test for the eleven RKR plugs. The table includes a column with the recovery at the end of the imbibition cycle (i.e. waterflood) which indicates what is the expected ultimate waterflood recovery under gravity stable conditions. The data vary significantly (32 % - 89 % OOIP) with an average value of 66 % OOIP recovery after waterflood, which is significantly higher than the 44 % OOIP estimated recovery from the field.

After the cores were brought to residual oil conditions, air was injected into the core and the GAIGI scheme was simulated in the ultracentrifuge at reservoir temperature. The fluid production was monitored at different centrifuge settings and the incremental recovery due to gas injection (drainage) was recorded. In Table 6, the oil saturation before and after air injection is presented for the eleven RKR plugs along with the incremental oil recovery. This recovery varies between 4 % and 22 % OOIP with an average value of 10.5 % OOIP which is significantly lower than other reported recoveries in long core floods. However, taking into account that there was no considerable oil stripping, this recovery is significant and shows that even at increased waterflood efficiencies, such as the ones achieved in the ultracentrifuge, incremental oil recovery can be achieved through GAIGI.

Three RKR plugs were aged for forty days in reservoir crude at their Swi saturations and the Amott USBM test was repeated. The objective was to see potential differences between preserved and restored core states. The wettability, saturation and gas injection results for these three plugs are shown in Tables 7, 8 and 9 respectively. In Table 7 the Amott and USBM results provide interesting information. The Amott wettability to water in general decreases. The Amott wettability to oil in two out of three cases increases. This is an indication that the wettability is shifting towards more oilwet conditions. The USBM indices also move to lower values an indication that the wettability moves towards weaker wetting conditions. The imbibition recovery is a lot higher (78.7 %, U.S. 64.7%, Table 8) on the average than the preserved plug tests. However, the average recovery after gas injection is pretty close to the preserved case (10.7 %, U.S. 12%, Table 9).

Table 10 summarizes all the preliminary results over and above the reservoir plug testing. Five Berea tests and nine Baker dolomite tests are reported. Three plugs were run at 25°C, three plugs were run at 87°C with the Amott tests at 40°C and the rest of the tests were all done at 87°C. The reason behind the 40°C tests was to make sure that there would be no losses of fluids due to evaporation. Some of the runs were not completed, because fluids were lost due to evaporation or damage in the Amott cups. When all the preliminary tests were done it was decided to perform the runs with minimum four hours per pressure step in the centrifuge, and five hours per step in the Amott cups. The preliminary data also indicated a shift of the wettability preference towards water wet conditions with increasing temperature. Therefore the operating temperature was the reservoir temperature. Rainbow Keg River "F" pool oil was used in all tests except for the very first trials (where "B" pool oil was used). This oil was not live. Therefore one could argue that exact reservoir conditions were not met. It was decided that the presented results were as close as possible to the actual reservoir conditions.

Tables 11 and 12 tabulate the fluid saturations for each end point of a pressurization cycle. All Rainbow plugs underwent the gas injection test, while only six of the preliminary tests included the extra step. It is important to note that incremental oil was produced in all the cases. Baker dolomite had the best performance (60 - 74 % of the residual oil after imbibition). The Berea plugs produced between 46 % and 70 % of the imbibition residual oil (15 % - 30 % OOIP) through immiscible gas injection. These results compare well with results in Berea cores which appear in the literature.

A series of six tests were performed in Berea plugs using Bayol synthetic oil. Three of them were run at room temperature and three at reservoir temperature. The tests were performed in an effort to evaluate the effect of possible water evaporation during the Amott test. There was no such effect observed. The cores indicated strong water wet conditions in both cases. The imbibition recovery varied between 59 % and 68 % (Table 14) and the gas injection results were higher than the "F" pool oil tests (24 % - 31 % OOIP).

A series of capillary pressure curves is presented next. Figure 21 provides the capillary curves for plug 9-28/1A. The primary and secondary drainage curves have end points (irreducible water saturation) which differ by about five percentage points. This is a type of centrifugal hysteresis which has also been observed in the literature (Hawkins and Bouchard, 1989; Honarpour *et al.*, 1990). Note that the irreducible water saturation is about 25% and the residual oil saturation approximately 45%. The capillary pressure curve for plug 9-28/2A (Figure 22) is considerably different. The irreducible water saturation is only 10% while the residual oil saturation only 15% which is typical of the well sorted unconsolidated systems rather than the heterogeneous dolomites. Similar is the capillary pressure curve of plug 9-

28/3A (Figure 23) and 9-28/8A (Figure 24). Both irreducible water and residual oil saturations are very low. A different picture is observed in Figure 25 for the sample 9-28/10A. Although the irreducible water saturation is 10% the residual oil is 30%. Taking into account the fact that the USBM index is greater than one (indicating water wet environment) one suspects that larger pores are surrounded by small pore throats. This type of pore space always results in increased residual oil saturation. Moreover, large aspect ratios are expected since most of the imbibition occurred during the spontaneous step. Sample 9-28/11A has low irreducible water and residual oil saturations. The discrepancy between primary and secondary drainage is again approximately five percentage points (Figure 26). The last of the presented plugs (9-28/14A, Figure 27) has a relatively high residual oil saturation (30%) but the irreducible wetting phase saturation discrepancy is quite large. With the exception of plug 9-28/1A the hysteresis between primary and secondary drainage is quite consistent in all 9-28 samples although the magnitude of the hysteresis varies. The irreducible wetting phase saturation is higher for primary drainage than secondary drainage in plug 9-28/1A but lower in the rest of the plugs.

A different picture was observed in the plugs from 6-6 (Figures 28-31). The four samples tested (6-6/1A, Figure 28; 6-6/2A, Figure 29; 6-6/4A Figure 30; and 6-6/5A, Figure 31) had distinctly different capillary pressure curves. Although they were all characterized by the relatively low values for the residual water saturation, 6-6/4A had a characteristic very high value for the residual oil saturation. The rest of the plugs had also low residual oil saturation. Within the two different drainage cycles, 6-6/1A was the only plug from all the tested plugs that primary and secondary drainage reached the same residual water value. Plug 6-6/2A had a higher secondary drainage residual water (compared to the primary drainage), while the opposite was observed in plugs 6-6/4A and 6-6/5A respectively.

The following three capillary pressure curves correspond to three Berea plugs. The tests were performed at 87°C. The curves (shown in Figures 32 to 34) are very similar and they are typical of a water wet system with large pore bodies surrounded by small pore throats. Very little spontaneous oil imbibition is observed while most of the water imbibed spontaneously. The following six capillary pressure curves (Figures 35 to 40) are for the Baker dolomite plugs. Since all plugs were cut from the same piece of rock, the differences in the capillary pressure and the corresponding wettability are attributed to the higher mobility of the oil at the elevated temperatures. All six curves exhibit extremely low irreducible water saturation. All six curves also exhibit very high residual oil saturation (45-60%). However, the spontaneous imbibition for the low temperature tests is much less efficient. The forced imbibition at the high temperature tests corresponds very little to the reduction of oil saturation. The consistency in the residual oil saturation is very encouraging and indicates that whether at high or low pressure, there is no residual oil mobilization.

The capillary pressure curves for the three restored state plugs from 9-28 are shown in Figures 41-43. All three curves have shifted towards higher oil saturations in both drainage and imbibition. The effect is more profound in drainage where the values of the "irreducible" wetting phase saturation have shifted towards higher values thus altering also the shape of the drainage capillary pressure curves.

For the plugs that were used for air injection after the residual oil saturation was reached, the productions of oil and water were monitored as a function of the increasing centrifugal force (in the form of RPMs). PORCAP is not capable of handling three phase systems. In this sense, we were forced to try a different approach. First we plotted the fluid saturations for all the tests in a series of tertiary diagrams (Figures 44 - 55). In these tertiary diagrams a number of interesting observations were made. Looking at the plots for 9-28/2A and 9-28/3A (Figures 44 and 45 respectively) one can observe that initially only water is produced. Oil is produced only at the last step. In 9-28/8A (Figure 46) some oil is produced with the water during the first pressure step but after that, only water is produced for two steps followed by both oil and water production. This behaviour is not consistent with what is observed in micromodels. 9-28/1A (Figure 47) produced water only during the first production step and after that nothing else was produced. The liquid production in 9-28/10A (Figure 48) is similar to the production of 9-28/8A but with more steps. 9-28/11A has the same characteristics as in 9-28/2A (Figure 49). Similar is the picture in 9-28/14A (Figure 50). When dealing with the plugs from 6-6 similar observations are made. 6-6/1A has simultaneous production of oil and water throughout the drainage process (Figure 51). In 6-6/2A there is only water production throughout the drainage process with only traces of oil (Figure 52). In Figure 53 we see that oil was produced in the beginning only for 6-6/4A. Finally, 6-6/5A has the stepwise character typical of the 9-28 plugs. For reference purposes the diagrams for the Berea plugs are shown in Figure 55. The broken lines are lines of equal RPM settings in the centrifuge (equal pressure lines). With the exception of the early Hassler and Brunner work, there is no other reference in the literature, to our knowledge, that deals with this type of tertiary diagrams.

Although the tertiary diagrams presented above provide illustrative information about the saturation history during the gas injection phase, there is no reference to the effect of pressure. In a number of cases, with Figure 47 the most clear, there was no additional production after the first pressure increase. As a result, a more appropriate representation was considered necessary. Since we could not find anything in the literature, we devised the following algorithm. We assumed that the complete representation of the system should be done through two sets of "parallel" capillary pressures one for the oil/gas interface and one for the water/oil interface. The two curves can be constructed by assuming one two phase system with water being the wetting phase and oil+gas being the non wetting phase, and one system where water+oil is the wetting phase and gas is the non wetting phase. The H.B. equation for the centrifuge can then be used for the calculation of the capillary pressure in each interface.

$$P_c = \frac{1}{2} \Delta \rho \omega^2 (r_2^2 - r_1^2)$$

Since the density of the combined phase is needed in each calculation, a weighted average density was calculated in each step. The production derived average saturations were used for the weight averaging. With this procedure the three phase capillary pressure systems were derived for each of the gas injection plugs (Figures 56 - 68). All plots have a common characteristic. The gas/oil capillary pressure is a little higher than the oil/water capillary pressure. This is physically correct. However, the curves are dramatically different from case to case. In this report the curves were drawn by joining the different points. It was noticed that in most cases, the low pressure points formed a straight line. This line was drawn and when intercepted the vertical line at the initial fluid saturations, the breakthrough capillary pressure was indicated. It must be noted that the curves from Berea are a lot smoother than the curves from the RKR plugs. This is at least partly due to the fact that Berea is a higher porosity system and the volumes measured were larger. However, Berea is also a lot more homogeneous. These curves could probably give us information about the heterogeneities in the cores. Figure 56 shows the capillary pressure for 9-28/1A. After the first RPM setting no more fluids are produced. The capillary curves are vertical lines. The curves for 9-28/2A are shown in Figure 57. The breakthrough capillary pressure and the different pore size systems can be shown. Similar is the behaviour in 9-28/3A (Figure 58), 9-28/8A (Figure 59), 9-28/10A (Figure 60), 9-28/11A (Figure 61), 9-28/14A (Figure 62) and 6-6/2A (Figure 63). In Figure 64, the breakthrough capillary pressure is quite high, over 10 kPa, and the rationale behind the choice of making the curves in this way is clarified. On the contrary, 6-6/5A (Figure 65) has a breakthrough capillary pressure less than 0.1 kPa. The Berea plots are also provided for comparisons (Figures 66 - 68). This type of information has never been published before. It must be also noted that we were not able to run tests at lower RPMs than the ones presented in this report due to hardware difficulties. It would be very informative if we could run tests at lower RPMs and get a better picture for the capillary pressures at such settings. This work opens a new area in the multiphase flow phenomena and it needs a lot more work.

The effect of H_2S on wettability was not assessed in the centrifuge tests. However, contact angle measurements with and without H_2S done in a specially designed visual cell shown in Figures 69 and 70. If the H_2S has no effect on the measured contact angle (as expected) then the scheduled core floods at reservoir conditions will be done without any H_2S present. This will reduce the safety precautions for the core floods. The contact angle work was subcontracted to Hycal Energy Research laboratories Ltd.

In order to begin a contact angle and/or interfacial tension measurement, the two fluids of interest (oil/brine or gas/brine) were contacted in a high pressure cylinder at 15168 kPag (2200 psig) and 87°C for several hours to eliminate mass transfer during the operation of the test. The two fluids were then separated into individual cylinders in preparation for the appropriate test.

Contact angle tests were carried out in a specially-designed, high-pressure sight cell which was provided by Nova-Husky Research Corporation for use in these particular tests. This cell contained an adjustable core sample mount and a bubble-injection needle situated directly below the mount to enable direct placement of fluids on the core.

Six small core samples were cut and polished in an air-free environment and left in the formation brine until required for the actual contact angle test. Once preparation for each individual test was completed, a new core sample was glued to the core sample mount and placed within the sight cell. For the first four tests, the contacted brine was then introduced into the cell. The brine was bled into the cell slowly until the pressure within the sight cell reached 15168 kPag (2200 psig). Additional brine was then displaced into the sight cell with air being bled out of the cell to maintain pressure. Brine was continually injected into the cell until the core sample was completely immersed. A bubble of the second fluid (H_2S -free oil, H_2S -rich oil, H_2S -free gas, or H_2S -rich gas) was then placed on the core sample surface through the bubble-injection needle. Photographs were then taken at various time intervals to measure the contact angle and also to ascertain whether any changes were occurring over time. The fluids contacted for the contact angle tests were also utilized in the interfacial tension tests.

The surrounding fluid (brine in the case of each of the oil/brine and gas/brine tests) was injected into a series of two cells. The first cell was a high-pressure Ruska cell which contained a small-diameter capillary tube for measurement of small volumes of fluid (volume/length of the capillary tube was calibrated to be $0.0624 \text{ cm}^3/\text{cm}$). The second cell was also a high-pressure sight cell, but was fitted with a 0.9 mm OD diameter injection needle (0.5 mm ID) at the bottom of the cell. The top of the cell was then connected to a cylinder containing pressurized N_2 which was employed to eliminate pressure fluctuations within the system.

Preparation for the test was then carried out by filling both of the cells with the surrounding fluid and adjusting the pressure in the N_2 -buffer bomb to the operating pressure of the test. The second fluid was then pushed through the cells until the production of bubbles could be observed in the second cell. At this time the brine was introduced into the line again until the brine/oil or brine/gas interface could be seen at the bottom of the capillary tube in the Ruska sight cell. At the moment that a bubble detached from the injection needle in the second sight cell, the level in the capillary tube was scoped with a cathetometer.

The procedure followed for dislodging further bubbles was to continue to inject fluid (brine) at a rate of $3 \times 10^3 \text{ cm}^3/\text{s}$. Just prior to detachment of the bubble, the pump was stopped and the oven was turned off to eliminate vibrational disturbances caused by the fan in the oven. Immediately after disengagement of the next bubble the level of the interface in the capillary tube was scoped and the oven was again turned on. This procedure was repeated for several bubbles (between 5 and 10) over which time the average volume of the bubbles was recorded. The average time for a bubble to be completely formed was between 1 and 2 minutes dependent upon the particular case.

Contact angle measurements were made for the H_2S -free oil/brine, H_2S -rich oil/brine, H_2S -free gas/brine, and H_2S -rich gas/brine systems from photographs taken at various time intervals during the individual tests. The first test involved the H_2S -free oil/brine system. Photographs were taken at intervals of 1, 6, 48 and 100 hours. No discernible change in the contact angle was observed over this time span. The contact angle was measured to be 28.4° through the water phase indicating strong water-wetness. In each of the subsequent tests, difficulty was encountered in maintaining a bubble on the surface of the core sample for the entire 100 hour duration of the test. Nevertheless, as in the case of the H_2S -free oil/brine system, no visible changes in the contact angles occurred over the time duration in which bubbles were situated on the surface of the core samples. For the H_2S -rich oil/brine system, a contact angle of 31.0° was measured. For the H_2S -free gas/brine system, the contact angle was measured to be 28.8° , while for the H_2S -rich gas/brine system it was 30.5° . In each of these cases strong water-wetness is exhibited and the effect of the presence of H_2S in the oil or gas upon the contact angle appears to be minimal.

The drop weight or drop volume method was the method used to measure the interfacial tensions at the elevated temperatures and pressures required for this test. In order to verify this method, an air/ H_2O system was tested at 87°C and atmospheric pressure. At these conditions an interfacial tension of 61.3 mN/m has been reported while the value obtained from this test was 63.9 mN/m. Adjustment of the needle internal diameter to 0.262 mm (0.524 mm ID), however, yielded the same result. Since thermal expansion may have been responsible for minute changes in the needle, this radius was used in all other calculations.

The data obtained from the series of drop volume tests is listed in Table 21. Also included in this table is a list of the measured densities of each of the test fluids. Based upon these results the presence of H_2S appears to have a significant effect upon interfacial tension. For the H_2S -free oil/brine system an IFT of 20.4 mN/m was measured, while for the H_2S -rich oil/brine system an IFT of 35.1 mN/m was measured. The contrast between the interfacial tensions for the H_2S -free and H_2S -rich gas/brine systems is also

appreciable with values of 29.3 mN/m and 48.3 mN/m measured for the H₂S-free and H₂S-rich systems, respectively.

Finally, in one of the centrifuge tests, where RKR "B" pool oil was used, a waxy residue was collected. This residue was sent to the analytical department for IR and ESM analysis. The analysis indicated that the peaks of the residue were similar to the peaks of the crude oil (Figures 71 to 73). However, the CH₂ rocking absorbances at 726 and 719 cm⁻¹ are resolved and at higher intensity relative to the other peaks in the region. This indicates that a larger proportion of high molecular weight aliphatic hydrocarbons (i.e. wax) was present in the sample. After thoroughly washing the solids with toluene and carbon disulfide, very little solids were noticeable. SEM/EDX analysis showed that mainly long rod-like crystals of calcium sulfate (Figure 74) remain. The EDX spectrum (Figure 75) indicates that smaller amounts of silica and chloride are present. Cubic sodium chloride crystals have been observed. The examination did not reveal any coke particles.

2.4 Ambient Systems

A series of tests in ambient systems was performed with the purpose of monitoring the recovery of residual oil with gravity assisted immiscible gas injection. The focus was on the effect of wettability and heterogeneities. Glass beads and sand from Aberfeldy were used as the porous matrix. Artificial vugs and fractures were made and inserted in the packs to study the effects of these heterogeneities. A summary of the results is recorded in Table 16. Out of the seven completed tests, two were performed in water wet systems, one in a mixed wet system and the rest in oil wet systems.

Six tests were run in Plexiglass columns of 0.05 m in diameter and 0.50 m in length. The columns were saturated with brine, then flooded with oil in a gravity stable mode to irreducible water. A waterflood followed in a gravity stable fashion. The waterflood continued until at least water breakthrough. At this point air was allowed to enter the system and displace oil and water. The rate was kept constant to 3 10⁻⁴ cm³/s by adjusting the production valve. A set of four such tests is shown in Figure 76. The three columns shown in the picture are filled with glass beads and contain artificial vugs. They are treated to be mixed wet, oil wet and water wet respectively from right to left. The column that is partially seen in the figure is the oil wet treated sandpack. Figure 77 shows the initiation of the oilflood which is completed in Figure 78. There are no photographs of the waterfloods because the contrast in the colour was not good. Figure 79 shows the gas injection which is continued in different stages through Figure 85. As it can be seen in all three glass bead columns the oil bank is formed and propagates downwards. The sandpack is not clear.

One of the tests was run in a complete rig with pressure and flow rate measurement devices. A schematic diagram of the rig is shown in Figure 75. The column in the rig was 0.10m in diameter and 1.0 m in length. These tests were very long and it was decided not to proceed with any additional tests of this kind until the decision point. We currently have two complete rigs that are ready to host equivalent amount of long cores at ambient temperature and pressure. The oil recovery for all the tests was remarkable. With the exception of column GB oilwet #2 the oil recovery in the glass bead columns was of the order of 65% or better. The exception case was the one where the waterflood efficiency resulted in very low waterflood residual oil saturation. For the sandpack the gas injection was more modest. It was also found that the rates of recovery was very fast. Gas broke through without any oil production. The columns were shut in. All the incremental oil was produced after the shut in. This indicates that the oil will drain even behind the gas front provided that the gas is not flowing freely. The implications of shut in could be very important for coned marginal wells. Further work is needed in this direction.

Figure 86 shows the waterflood production curves for all the small columns. The success of the oil wet treatment can be demonstrated with these plots. With reference to the water wet case each column behaves more oil wet. The individual waterflood and gas injection for each column are presented next. First for the water wet glass bead column (Figures 87 and 88). Please observe the production of oil corresponds to the point of reduced water production. The vugs do not appear to have any significant effect. The following two figures (89 and 90) show the corresponding curves for the oil wet column of Figures 76 to 85. Similar observations can be made. The same behaviour is shown in Figures 91 and 92 for the mixed wet column. The characteristics of the small oil wet sandpack are given in Figures 93 and 94. As it was stated earlier, there was no oil production at gas breakthrough. The column was shut in under 69 kPa gas pressure for one day. When the column was put back on production all the oil was produced. The two last small columns' characteristics are plotted in Figures 95 to 98. These are the two more extreme cases. The first column was almost complete oil recovery. This is more typical of the water wet systems reported in the literature indicating a poor treatment with the hydrophobic agent. The second column had the lowest recovery. This is a characteristic of an oil wet column with a very high waterflood efficiency. The oil is almost at its irreducible saturation and the additional oil recovery by gas injection is very limited.

The production characteristics of the large sand pack are shown in Figures 99 to 103. Figure 99 shows the production curve for the waterflood step. It is a typical waterflood for a water wet reservoir. The corresponding pressure build up is given in Figure 100. Figure 101 shows the production characteristics during the gas injection. The production of oil water and gas are all monitored. Please note the jump in production after each shut in period. The same observation can be made by looking at the production rate peaks in Figure 102. Finally the pressure build up curve for the gas injection is shown in Figure 103.

Although the rate of production was fast, and shut in had to be implemented, this way of well production may indeed be a viable recovery strategy option.

3.0 DISCUSSION

The presented results clearly indicate that gravity assisted immiscible gas injection is promising even in an environment similar to the one of Rainbow Keg River "F" pool. The expected incremental recovery will depend on the way fractures are distributed in the reservoir. It will also depend on the local waterflood efficiency. The following sections summarize the findings of the experimental work.

3.1 Micromodel tests

The purpose of the micromodel tests was to study the gas displacement mechanism under varying conditions of wettability and pore geometry. Both the waterflood recovery and the gasflood recovery showed a strong correlation with pore geometry in the micromodel tests. The key geometrical characteristics are the aspect ratio, which is defined as the ratio of the pore body diameter to pore throat diameter, and the pore size distribution. Micromodels with large aspect ratios and wider pore size distributions gave lower waterflood recovery and higher incremental gasflood recovery and vice versa. A plot showing the incremental gasflood recovery versus waterflood recovery from micromodels is shown in Figure 105.

The ultimate waterflood recovery from "F" Pool will be approximately 53 % OOIP according to field data. From Figure 104, this would correspond to an incremental gasflood recovery of approximately 13% for an ultimate recovery of 66 %. However, one should bear in mind that the micromodels are only two dimensional, and are used for the study of displacement mechanisms. The use of micromodels has shown that an oil bank is formed and propagates downward in a gravity stable manner with high sweep efficiency. The average pore size in the micromodels is fairly large. Therefore the results should be considered as more representative of the fracture/vug system than the matrix. A system of large vugs interconnected by tiny fractures or matrix pore throats would certainly be described as a high aspect ratio system. Therefore, the results from the micromodel tests suggest that the waterflood recovery from the vug system in "F" Pool may be fairly low, and that the incremental gasflood recovery could be fairly high. Previous studies have shown that the vugular porosity represents 42 % of the total porosity, so that the overall recovery efficiency is strongly affected by the recovery efficiency in the vugs. Neither the waterflood recovery nor the gasflood recovery were strongly affected by the wettability in the micromodel experiments. Identical tests were performed with only the wettability altered, and reasonably consistent

results were obtained. This may have been because wall effects are diminished when the average pore size becomes larger. This would imply that the wettability in the vugs is not an important parameter for predicting recovery. However, with all the problems associated with wettability alteration this result should be used with caution.

3.2 Centrifuge tests

The primary objectives of the centrifuge tests was to determine the wettability and capillary pressure characteristics of the formation. Centrifuge tests were performed on preserved reservoir core, at ambient pressure, using dead reservoir oil and synthetic formation brine. It was discovered that temperature had a strong effect on wettability, so all centrifuge tests performed on reservoir core were run at reservoir temperature (87°C). Parallel tests run in Core Laboratories at room temperature (25°C) showed some correlation between wettability and porosity. Lower porosity samples tended to be more water wet and higher porosity samples tended to be more oil wet. From this it was inferred that the matrix tends to be water wet and the vugs tend to be oil wet. However, the results obtained in NHRC did not show any correlation between wettability and porosity. Figure 106 is a plot of the Amott wettability index to water as a function of porosity. There is a weak trend for higher index when the porosity increases and when the temperature increases. Similar but not as clear effect is shown in the plot of the Amott wettability index to oil as a function of porosity (Figure 107). In general, at reservoir temperature, the USBM wettability indices were positive, indicating predominantly water wet conditions. The USBM results show also increased water wet characteristics with increased temperatures. The Amott wettability indices confirmed that the wettability is fractional with tendencies for both spontaneous drainage and spontaneous imbibition. At room temperature, the USBM indices shifted towards oil wet conditions, probably due to the precipitation of sticky hydrocarbons (wax). There was no correlation of USBM index and porosity (Figure 108). Cross plots of Amott and relative displacement indices with the USBM index showed that although the vugs may vary from strongly oil wet to strongly water wet, the matrix is weakly to strongly water wet (Figures 109 to 111).

A very interesting application of the centrifuge technique was the implementation of gas drainage starting at residual oil conditions and the monitoring of the incremental oil recovery, with the additional bonus of the determination of the three phase saturation scheme. Initially, it was assumed that it would be impossible to obtain reliable displacement efficiency results from centrifuge data due to scaling problems (i.e. finite core length effects and critical Bond number effects). Later in the project, however, it was discovered from the literature that by properly designing the experiment, and within a specific range of permeability, reliable results could be obtained without encountering scaling problems. Preserved core plugs from "F" Pool along with Berea plugs and Baker dolomite plugs were centrifuged under oil to

connate water, under water to residual oil and finally under air to tertiary residual oil. Published criteria were applied to screen the results. In particular the mid core Bond number was calculated for each displacement test (i.e. each RPM setting). A test was considered satisfactory if the Bond number did not exceed the value of 10^{-5} . Based on the tests which satisfied this criterion, the average waterflood displacement efficiency was 66 % and the average gasflood incremental displacement efficiency was 9 %. As with the micromodel tests, higher waterflood recovery was associated with lower incremental gas flood recovery and vice versa, although the correlation was not as strong. A series of plots of waterflood and gas flood recovery from the centrifuge data is shown next. The core permeabilities are also shown. The brine vs air permeability for the plugs used to this point is shown in Figure 112. Figure 113 shows the waterflood recovery efficiency as a function of midcore Bond number for the plugs from 9-28-108-7W6M. It can be seen that although in some cases the waterflood (imbibition) went up to Bond numbers of 5×10^{-4} , there was no recovery of oil for Bond numbers higher than 2×10^{-5} , which is very close to the imposed criterion. The corresponding results for the gas injection phase and the plugs from the same well, are shown in Figure 114. In this figure one can see that for the high permeability cores there was significant recovery of oil past the cut-off point. It is yet to be determined whether this constitutes stripping or not. Similar results for well 6-6-109-7W6M are shown in Figures 115 and 116. Again the high permeability cores produced incremental oil after the Bond cut off point. The total oil recovery plots during both waterflood and gasflood are shown in Figures 117 and 118 respectively. A plot showing the incremental gasflood recovery versus waterflood recovery from centrifuge tests is presented in Figure 119. From this figure, an ultimate waterflood recovery of 53 % would correspond to an incremental gasflood recovery of 10 %.

Further work must be done to prove that the published criteria are valid, and a much larger population of samples must be tested. The standard deviation was fairly high in the presented results, but with a larger population of samples, the results could be grouped by rock type, which may reduce the standard deviation.

3.3 Unconsolidated coreflood tests

The purpose of the unconsolidated coreflood tests was to evaluate the tertiary gasflood process in porous media containing vugs under varying conditions of wettability. Although a large number of "vugs" were placed in the columns, the vugular porosity represented a very small fraction of the total porosity. This was because the matrix porosity in the packed columns was very high compared to the field situation. Vugular porosity represented only 5% of the total porosity in the packed columns, compared to 42 % in the reservoir, so that the effect of the vugs was probably not represented accurately in the results from these tests. The average waterflood displacement efficiency was 75 % and the average incremental

gasflood displacement efficiency was 15 %. As with the micromodel tests a correlation was observed between waterflood recovery efficiency and incremental gasflood recovery efficiency. A plot showing the incremental gasflood recovery versus waterflood recovery from the unconsolidated coreflood tests is presented in Figure 120. A comparison with literature data (Dullien *et al.* 1991) is also shown. It can be seen that an ultimate recovery of 53 % would correspond to an incremental gasflood recovery of 13 % for an ultimate recovery of 66 %. The results from these tests indicate that there is no correlation between wettability and incremental gasflood recovery, even for a predominantly "matrix" system. However, in several cases, particularly in the oil wet columns, the waterflood portion of the test was truncated before reaching the ultimate waterflood residual. Some of the oil recovery identified as incremental would have been obtained anyway under continued waterflood. In general it is expected that the gasflood incremental recovery would be lower from oil wet matrix than from water wet matrix.

3.4 Future work

The future work in this area includes long core floods at ambient and reservoir conditions, continuation of the characterization measurements using the centrifuge and our permeameters, and reservoir characterization measurements using the CAT scanner. Another point of interest is the number of new areas that are opening for research. Understanding the distribution and connectivity of vugs and fractures is predominant. How to calculate three phase capillary pressures is also very important. Finally how to prevent gas channelling will become very challenging when trying to implement the process in the field. If the centrifuge is providing us with gravity stable tests, a large number of tests can be performed at a relatively low cost. In particular, the use of centrifuge for three phase capillary pressure tests as well as the spontaneous imbibition in two phase tests has not been adequately addressed in the literature. All these issues are worth further investigation.

4.0 MODELING AND COMPUTER SIMULATION

4.1 Introduction

The generated results need to be matched by an appropriate model that will allow for sensitivity analysis and production forecasting under different conditions. At first, CMG IMEX was compiled and set for matching of laboratory experiments. It was found that this model is not capable of handling small ambient systems. As a result, a simple one dimensional reservoir model was designed and developed. Both models were built with the plan of matching both waterflooding and gas injection experiments. A

novel grid set up algorithm was developed for use in the in-house model. The new set up eliminates numerical dispersion problems at the front which are a common problem in conventional simulators.

4.2 Installation and Testing of CMG IMEX

Using the IMEX program, series of calculations have been carried out to model numerically water and gas injection experiments. A vertical waterflood from the bottom of a one meter column was replaced with a gas injection from the top of the column. The switching of the injection pattern took place after sixty minutes of the waterflooding. The following Figure 146 illustrates the model and positions of injectors and producers:

The list of input data contained following rock and fluid properties:

- porosity equal to 0.20 for all (1-10) blocks,
- rock compressibility was set to zero,
- rock permeability was equal to 500 (mD) for each block,
- the fluid densities were equal to 0.700, 0.001, and 1.000 for oil, gas, and water accordingly.

In addition, the PVT data were taken from Tables 17 - 19.

The capillary pressure values have been modified to test the sensitivity of the results on these data. The following variants were considered:

1. The values of the capillary pressure (P_c) were multiplied by 0.01 and the oil formation volume factor (B_o) was set to 1.0. The Figure 147 shows oil and water saturation profile changes during sixty minutes of waterflooding. The program, however, failed to switch to a gas injection mode. Figure 148 depicts shapes of reservoir pressure curves during the waterflooding.
2. When the oil formation volume factor was assumed to be greater than 1.00 (as in the Table 17) the program ran properly with the capillary pressure values the same as in the previous (1.) case. The results are shown in Figure 149 (saturation profiles).

One can notice a change in the saturation curve shape at the time - $t = 0.042$ [day] = 1 hour i.e. when the water injection from the bottom (5.0cm) was replaced with a gas injection from the top (95.0 cm).

3. Multiplying the original capillary pressure values, taken from Table 19, by 0.1 gave results shown in the Figures 150 and 151. We can notice that an instant flooding occurred. Moreover, the program failed to switch to the gas injection mode.
4. Taking the capillary pressure values from Table 19 without any modifications resulted in saturation profiles and pressure curves plotted in the Figures 152 and 153. Again, the flooding was even more unrealistically instant and the program was neither able to continue calculations nor to switch to the gas injection mode after time - $t = 0.042$ [day].
5. After having set the capillary pressure values to zero, the program did run properly and results are depicted in the Figures 154 and 155. A concave shape of the oil saturation curve may be seen from the start of the gas injection ($t = 0.042$ [day]) until $t = 0.08$ [day]; whereas, in the case of non-zero capillary pressure ($pc \neq 0$) it lasted a little longer - until $t = 0.106$ [day].

4.3 Multiphase Flow Equations

4.3.1 Statement of the Problem

The flow of immiscible fluids in a porous medium can be macroscopically described by relative permeability equations which are generalizations of Darcy's Law.

The problem is stated as follows:

there is a reservoir with a given geometry and saturations in three fluids 1, 2 and 3 distributed in a given manner. For a projected production requirement an attempt is made to calculate - at every point in the reservoir and with respect to time - the following parameters:

- a) pressure in each of the fluids p_1 , p_2 and p_3
- b) saturation in each of the fluids S_1 , S_2 and S_3
- c) density of each of the fluids ρ_1 , ρ_2 and ρ_3
- d) viscosity of each of the fluids, μ_1 , μ_2 and μ_3
- e) filtration velocity of each of the fluids, U_1 , U_2 and U_3

Thus, twenty one equations must be written to state the problem completely.

4.3.2 General Equations

Relative permeability equations:

$$\bar{u}_v = -\frac{kk_{rv}}{\mu_v}(\nabla p_v - \rho_v \bar{g}) \quad (4.3.2a)$$

$$v = 1, 2, 3$$

Equations of state:

(for iso-thermic, immiscible flow it is assumed that the density and viscosity of each of the fluids are definite functions of the pressure)

$$\rho_v = \rho_v(p_v)$$

$$\mu_v = \mu_v(p_v) \quad (4.3.2b)$$

$$v = 1, 2, 3$$

Equation of continuity:

$$\sum_{v=1}^3 S_v = 1$$

expresses the fact that the pores of the medium are entirely occupied by the fluids.

The next three equations express the conservation of each of the fluids:

$$\text{div}(\rho_v \bar{u}_v) + \phi \frac{\partial(\rho_v S_v)}{\partial t} = 0 \quad (4.3.2c)$$

$$v = 1, 2, 3$$

where:

$$\text{div } \vec{u} = \frac{\partial u_x}{\partial x} + \frac{\partial u_y}{\partial y} + \frac{\partial u_z}{\partial z}$$

j = porosity.

The Capillary Pressure Equations:

$$\begin{aligned} p_2 - p_1 &= p_{c_{21}}(S_1) \\ p_3 - p_2 &= p_{c_{32}}(S_2) \end{aligned} \quad (4.3.2d)$$

complete the mathematical description of the problem.

We can choose a capillary pressure function which is suitable for the problem being studied. In some more subtle problems, the capillary pressure relationship can be modified so that to accommodate, for example, the changes of the direction of variations of S_1 and S_2 .

These relationships add the flexibility to the formulation and allow consideration of different flow modes in the reservoir.

4.3.3 Initial and Boundary Conditions

In addition to the governing equations, other equations must be added to express the initial state of the reservoir as well as to take into account the different production regimes (for example: injection under constant pressure or at constant rate in some wells and production through other wells). These equations describe the initial and boundary conditions.

The initial conditions are following:

- the values of pressure in each of the fluids p_1 , p_2 , and p_3 at time $t = 0$
- the values of saturations in each of the fluids S_1 , S_2 , and S_3 at time $t = 0$

Moreover, these data are not independent for they must satisfy the equations:

$$S_1 + S_2 + S_3 = 1 \quad (4.3.3a)$$

and

$$\begin{aligned} p_2 - p_1 &= p_{c_{21}}(S_1) \\ p_3 - p_2 &= p_{c_{32}}(S_2) \end{aligned} \quad (4.3.3b)$$

The boundary conditions express following facts:

a) Impermeability of the surface

The filtration velocities, $\bar{U}_1$, $\bar{U}_2$ and $\bar{U}_3$, tangent to this surface, must satisfy the equations:

$$\bar{U}_1 \cdot \bar{n} = \bar{U}_2 \cdot \bar{n} = 0 \quad (4.3.3c)$$

where $\bar{n}$ is a vector perpendicular to the impermeable surface.

b) Separation of the media with different properties

Equal pressure must be expressed on both sides (I, II) of the separation surface. Moreover, the rates of flow of each of the fluids through this surface must also be expressed.

$$\begin{aligned} (p_v)' &= (p_v)'' \\ (\bar{U}_v \cdot \bar{n})' &= (\bar{U}_v \cdot \bar{n})'' \end{aligned} \quad v = 1, 2, 3 \quad (4.3.3d)$$

(The superscripts I and II indicate the media)

c) Contact with outside world

(for example: through well bores in injection and production wells)

If a single fluid (fluid 1, for example) cross the boundary surface of the porous medium, the condition

$$\begin{aligned} (\bar{U}_2 \cdot \bar{n})' &= (\bar{U}_2 \cdot \bar{n})'' \\ (\bar{U}_3 \cdot \bar{n})' &= (\bar{U}_3 \cdot \bar{n})'' \end{aligned} \quad (4.3.3e) \quad (5.3)$$

must be replaced by:

$$(\bar{U}_2 \cdot \bar{n})' = (\bar{U}_3 \cdot \bar{n})'' \quad (4.3.3f)$$

which shows that the surface behaves as through impermeable to the fluids 2 and 3.

Since the total rate of flow in the whole well is set, the equation

$$(\bar{u}_1 \cdot \bar{n})' = (\bar{u}_1 \cdot \bar{n})'' \quad (4.3.3g)$$

must be integrated over the whole surface of the well:

$$\iint_{\Sigma} \bar{u}_1 \cdot \bar{n} d\sigma = Q \quad (4.3.3h)$$

Also the pressure loss law for the fluid flow in the well should be given (in simplest case - by the hydrostatic laws):

$$p_1(z) = p_1(z_0) + \int_{z_0}^z \rho_1 g \, dz \quad (4.3.3i)$$

The multidomain method, developed at NHRC, will allow easy implementation of these and other boundary conditions which may be needed when attempt is made to combine the macro and micro model flow. This method would also allow more detailed treatment of the moving front zones in immiscible displacements.

4.4 One Dimensional Displacement Equations

4.4.1 Problem Statement

Let us consider a cylindrical porous medium with a vertical $0x$ axis. The flow is parallel to $0x$. In addition, the pressure and saturations are uniform in each layer perpendicular to $0x$. Incompressible fluids 1, 2 and 3 are injected at one end at given filtration velocities, u_{10} , u_{20} and u_{30} . The viscosities of fluids 1, 2 and 3 are assumed to be constant.

Then, equations (4.3.2.a) - (4.3.2d) become:

$$u_v = \frac{k k_{r_v}}{\mu_v} \left(\frac{\partial p_v}{\partial x} - \rho_v g \right) \quad v = 1, 2, 3$$

$$\sum_{v=1}^3 S_v = 1 \quad (4.4.1a)$$

$$\frac{\partial u_v}{\partial x} + \phi \frac{\partial S_v}{\partial t} = 0$$

$$p_2 - p_1 = p_{c_1}(S_1)$$

$$p_3 - p_2 = p_{c_2}(S_2) \quad (4.4.1b)$$

where: u_1, u_2 , and u_3 are the algebraic values of the components of the filtration velocities on Ox and g is the algebraic value of the component of the acceleration of the gravity on Ox .

Let denote

$$u = \sum_{v=1}^3 u_v \quad (u - \text{total velocity})$$

$$\lambda_v = \frac{k k r_v}{u \mu_v}$$

and

$$f_v = \frac{u_v}{u}$$

Since

$$\sum_{v=1}^3 f_v = 1$$

the first three of the equations (4.4.1a) may be written in the form:

$$\begin{aligned} -\frac{1}{\lambda_1} f_1 &= p_1 - p_1 g \\ -\frac{1}{\lambda_2} f_2 &= p_2 - p_2 g \\ \frac{1}{\lambda_3} f_1 + \frac{1}{\lambda_3} f_2 &= p_3 - p_3 g + \frac{1}{\lambda_3} \end{aligned} \quad (4.4.1c)$$

Utilizing the capillary pressure equations we obtain the system of equations involving function f_1 and f_2 :

$$\frac{1}{\lambda_1} f_1 - \frac{1}{\lambda_2} f_2 = p_{c_{21}} - g_{21} \quad (4.4.1d)$$

$$\frac{1}{\lambda_1} f_1 + \left(\frac{1}{\lambda_2} + \frac{1}{\lambda_3} \right) f_2 = p_{c_{22}} - g_{32} + \frac{1}{\lambda_3}$$

+

$$g_{i,i+1} = (\rho_{i+1} - \rho_i) g, \quad i = 1, 2$$

The partial flow functions f_1, f_2 are determined from the above system and may be expressed in a matrix-vector form:

$$(f) = (\varphi) + [\Psi](S_x) \quad (4.4.1e)$$

where:

$$(f) = (f_1, f_2)^T$$

$$(\varphi) = (\varphi_1, \varphi_2)^T$$

$$[\Psi] = \begin{pmatrix} \Psi_{11} & \Psi_{12} \\ \Psi_{21} & \Psi_{22} \end{pmatrix}$$

$$(S_x) = \left(\frac{\partial S_1}{\partial x}, \frac{\partial S_2}{\partial x} \right)$$

and

$$\varphi_1 = \frac{\lambda_1}{\lambda_1 + \lambda_2 + \lambda_3} (-g_{21}\lambda_2 - \rho_{31}\lambda_3 + 1), \quad \varphi_2 = \frac{\lambda_2}{\lambda_1 + \lambda_2 + \lambda_3} (-g_{21}\lambda_1 - \rho_{32}\lambda_3 + 1)$$

$$\Psi_{11} = \frac{\lambda_1}{\lambda_1 + \lambda_2 + \lambda_3} (\lambda_2 + \lambda_3) \frac{\partial p_{c_{21}}}{\partial S_1}, \quad \Psi_{21} = \frac{\lambda_2}{\lambda_1 + \lambda_2 + \lambda_3} (-\lambda_1) \frac{\partial p_{c_{21}}}{\partial S_1}$$

$$\Psi_{12} = \frac{\lambda_1}{\lambda_1 + \lambda_2 + \lambda_3} (\lambda_3) \frac{\partial p_{c_{22}}}{\partial S_2}, \quad \Psi_{22} = \frac{\lambda_2}{\lambda_1 + \lambda_2 + \lambda_3} (\lambda_3) \frac{\partial p_{c_{22}}}{\partial S_2}$$

Since $\text{div } u = 0$ for the incompressible flow, the mass conservation equations

$$\text{div } \bar{u}_v + \phi \frac{\partial S_v}{\partial t} = 0 \quad v = 1, 2, 3$$

are transformed into

$$u \cdot \text{div } f_v + \phi \frac{\partial S_v}{\partial t} = 0 \quad (4.4.1f)$$

For the sake of simplicity let write equations (4.4.1e) for one dimensional case:

$$u \frac{\partial f_v}{\partial x} + \phi \frac{\partial S_v}{\partial t} = 0 \quad (4.4.1g)$$

After differentiation, the conservation equations take the form:

$$v_{11}S_{1x} + v_{12}S_{2x} + S_1 = \frac{u}{\phi} [(\Psi_{11}S_{1x})_x + (\Psi_{12}S_{2x})_x] \quad (4.4.1h)$$

$$v_{21}S_{1x} + v_{22}S_{2x} + S_2 = \frac{u}{\phi} [(\Psi_{21}S_{1x})_x + (\Psi_{22}S_{2x})_x]$$

where

$$v_{ij} = \frac{u}{\phi} \frac{\partial \phi_i}{\partial S_j} \quad (i, j = 1, 2)$$

The matrix-vector form of equations describing the three-phase immiscible flow in a porous medium is following:

$$[v](S_x) + ([D](S_x))_x + (S) = (0) \quad (4.4.1i)$$

$$(\text{assuming } [D] = -\frac{u}{\phi} [\Psi]_x)$$

The nonlinear, second order, partial differential equation is of parabolic type and contains the unknown functions S_1, S_2 .

Thus, the solution of the system of equations (4.4.1a) has been reduced to the solution of a single partial derivative equation (4.4.1h).

Once the latter is solved for the suitable initial and boundary conditions, S_1 , S_2 are known functions of x and t . Then we are able to calculate (j) , $[Y]$. Having known (j) and $[Y]$ the calculations of f_1 , f_2 as well as u_1 , u_2 and u_3 are straightforward. The first three of equations (4.4.1a) give

$$\frac{\partial p_1}{\partial x}, \frac{\partial p_2}{\partial x}, \frac{\partial p_3}{\partial x}$$

from which, by integration, p_1 , p_2 and p_3 , are determined to within an arbitrary time function (the reference level of pressures remains indeterminate for incompressible fluids).

Thus, once equation (4.4.1h) is solved, the problem described by equations (4.4.1a) is completely solved.

4.5 The Solution of the Saturation Equation for Two-Phase Flow

4.5.1 Case A: Negligible Capillary Forces

Under this assumption, the equation (4.5.1h) takes the form:

$$\left(\frac{u}{\phi} \frac{\partial \phi_1}{\partial S_1} \right) \frac{\partial S_1}{\partial x} + \frac{\partial S_1}{\partial t} = 0 \quad (4.5.1a)$$

(because $\frac{\partial p_c}{\partial S} = 0$
and therefore $Y_{11} = 0$)

This quasi linear homogeneous equation of first order may be solved easily by the method of characteristics. If we denote

$$w = \frac{u}{\phi} \frac{\partial \phi_1}{\partial S_1}$$

then the characteristic differential system for the equation (4.5.1a) is of the following form:

$$\begin{aligned} \frac{dx}{d\lambda} &= w \\ \frac{dt}{d\lambda} &= 1 \\ \frac{dS_1}{d\lambda} &= 0 \end{aligned} \quad (4.5.1b)$$

The integrals of this system are curves in the space (x, t, S_1) parametrized by l , and are at every point tangent to the vector $(2, 1, 0)$. The surface generated by a family of characteristic curves is a solution of the equation (4.5.1a).

The solutions of the characteristic system (4.5.1b) have the following fundamental property:

if a solution has the value $S_1 = S_{10}$ at point x_0 and at time t_0 , it will have, at point

$$x_0 + \lambda \frac{u}{\phi} \frac{\partial \phi_1}{\partial S_1}$$

and at time $t_0 + l$, the same value S_{10} .

This way we can plot the successive saturation profiles for various values of time (Figure 121).

From the shape of the function j_1 it is evident that not all of the saturation profiles are physically acceptable (two different value of saturation at the same point x). It is worth noting that this difficulty has appeared only because of neglecting the capillary pressure term in the equation (4.5.1h). The solution of the complete equation is free from this problem.

To alleviate this difficulty, the surfaces of discontinuity (or shock waves) have been introduced. In the case of the saturation equation being considered, the existence of a saturation discontinuity has been assumed. The theoretical saturation profile is replaced by a profile with a saturation discontinuity, coinciding elsewhere with the theoretical profile (Figure 122).

Although the saturation profile found by the method of characteristics has no physical meaning it does, however, satisfy the condition of material balance for the injected field.

The position of discontinuity (introduced to restore the physical meaning of the solution) can be determined in the following way:

at the time $t = 0$, the porous medium contains fluid 1 at saturation S_{1a} (independent of x), and fluid 2 at saturation $1 - S_{1a}$. At the $x = 0$ end fluid 1 is injected at the constant filtration velocity $j_{1a} \cdot x u$, and fluid 2 at the filtration velocity $(1 - j_{1a})u$. The saturation at $x = 0$ is fixed from the beginning of the injection at the values S_{1b} so that

$$\phi_1(S_b) = \phi_b. \quad (4.5.1c)$$

The method of characteristics permits the determination of the theoretical saturation profiles at subsequent times θ , 2θ , ... etc. by affinity in relation to the saturation axis:

$$x(S_1, \lambda\theta) = x\theta w(S_1) = \lambda x(S_1, \theta) \quad (4.5.1d)$$

We need only to determine the position of discontinuity at a given time $t = q$. The position of discontinuity at other moments in time may be deduced from it by affinity.

If we denote

$$w(S_1) = \frac{u}{\phi} \frac{\partial \phi_1}{\partial S_1} \quad (4.5.1e)$$

then the equality of the shaded areas in the Figure 2 is expressed by equation:

$$\theta w(S_r)(S_r - S_a) = \int_{S_a}^{S_r} \theta w(S_1) dS_1 \quad (4.5.1f) \\)))$$

or equivalently

$$(S_r - S_a) \left(\frac{\partial \phi_1}{\partial S_1} \right) \bigg|_{S_1 = S_2} = \int_{S_a}^{S_r} \frac{\partial \phi_1}{\partial S_1} dS_1 = \phi_1(S_r) - \phi_1(S_a)$$

Albeit the practical importance of the solution of the equation (4.5.1a) is very limited, it is very useful for testing new numerical schemes.

The method used in solving the homogeneous equation (4.5.1a) gave rise to a new numerical method for solution the complete equation (4.5.1h) as in the following case.

4.5.2 Case B: The Saturation Equation with the Capillary Pressure Term

The general form of the equation (4.5.1h) is as follows:

$$S_t + K(\chi, \tau) S_x = \lambda(\chi, \tau) S_x \chi + F(\chi, \tau) \quad (4.5.2a)$$

In a dimensionless form it can be written:

$$S_i + wS_x = DS_{xx} + f \quad (4.5.2b)$$

where:

$$t = \frac{\tau}{\tau_0} \quad x = \frac{\chi}{L} \quad w = \frac{k\tau_0}{L} \quad D = \frac{\lambda\tau_0}{L^2} \quad (4.5.2c)$$

In order to avoid the negative effects pertaining to the numerical diffusion and to the grid orientation, new numerical schemes (based on Wheeler *et al.* (1988) and Douglas (1983)) have been devised.

Wheeler *et al.* (1988) proposed to approximate the equation (4.5.2b) by an expression:

$$\frac{S_i^{n+1} - S_i^n}{\Delta t} = D \cdot C \quad (4.5.2d)$$

where:

$$C = \frac{2}{h_i + h_{i+1}} \left[\frac{S_{i+1}^n}{h_{i+1}} + \frac{S_{i-1}^n}{h_i} - \frac{S_i^n(h_i + h_{i+1})}{h_i h_{i+1}} \right] \quad (4.5.2e)$$

h_i - the size of the i th interval of the nonuniform grid $u_i = x_i - x_{i-1}$

Δt - time step

$$x_i^{n+1} = x_i^n + w(x_i^n, S_i^n) \Delta t \quad (4.5.2f)$$

The creation of the grid at consecutive time levels is depicted on the Figures 123 - 125.

Albeit the Dynamic Grid approach is a very convenient and effective tool for handling two-phase flow problems with moving fronts, it cannot, however, be used for solving polyphasic flow problems (i.e. when more than one moving front is involved).

In order to conserve benefits of the Method of Characteristics and still be able to handle a few moving fronts, we propose the following approach. Instead of calculating a new value of x coordinate at a new time level $x_i^{(n+1)}$ from the formula:

$$x_i^{(n+1)} = x_i^{(n)} + w(x_i^{(n)}, S_i^{(n)}) \cdot \Delta t$$

we calculate a value of $\xi_i^{(n)}$ at the old time level $t^{(n)}$ from the formula:

$$x_i^{(n+1)} = \xi_i^{(n)} + w(\xi_i^{(n)}, S^{(n)}(\xi_i^{(n)})) \cdot \Delta t$$

assuming that the value of $x_i^{(n+1)}$ is given (known). It is worth to note that we assume merely that the x coordinate at the new time level is known. The value of x may still vary for different time levels. This feature will be utilized in solving multiphase flow problem. The illustration of this concept is given in the Figure.

Although the numerical dispersion is significantly lowered by the explicit scheme, the stability of the solution is, however, severely restricted.

The stability of this method is limited for two reasons:

1. the diffusion term is taken explicitly, and
2. the moving front usually is very steep (the changes in saturation in x direction are significant)

In order to overcome the first problem we treated the $D \cdot S_{xx}$ term implicitly, whereas the second difficulty may be alleviated by introducing a new scheme containing only time derivatives; the positions in space would be calculated.

In more detail:

The equation (4.5.1h):

$$wS_x + \xi + (\psi_{11}S_x)_x = 0 \quad (4.5.2g)$$

was approximated by the following implicit scheme:

$$S_i^{n+1} - S_i^n = -\frac{U}{\phi} \Delta t (\nabla \Psi^{n+1} S^{n+1})_i \quad (4.5.2h)$$

Defining a function

$$\gamma(S_i^{n+1}) = S_i^{n+1} + b \cdot (\nabla \gamma^{n+1} \nabla S^{n+1})_i - S_i^n = 0 \quad (4.5.2i)$$

and applying Newton-Raphson method, this equation is linearized giving:

$$\frac{\partial \Psi}{\partial S} \delta S = -\Psi^{(m)} \quad (4.5.2j)$$

where

$$\frac{\partial \Psi}{\partial S} = 1 + b \cdot \left(\nabla \frac{\partial \Psi}{\partial S} \delta S \nabla S^{(m)} + \nabla \Psi^{(m)} \nabla \delta S \right) \quad (4.5.2k)$$

The term $\nabla \Psi \nabla C$ is approximated by:

$$\left[\frac{\Psi_{i+1/2}}{X_{i+1} - X_i} (C_{i+1} - C_i) - \frac{\Psi_{i-1/2}}{X_i - X_{i-1}} (C_i - C_{i-1}) \right] / (X_{i+1/2} - X_{i-1/2}) \quad (4.5.2l)$$

where

$$\Psi_{i+1/2} = \theta \cdot \Psi_{i+1} + (1 - \theta) \Psi_i \quad (4.5.2m)$$

$$\Psi_{i-1/2} = \theta \cdot \Psi_i + (1 - \theta) \Psi_{i-1}$$

$$\nabla \frac{\partial \Psi}{\partial S} \delta S^{(m)} \equiv \alpha_{1i} \delta S_{i-1} + \beta_{1i} \delta S_i + \gamma_{1i} \delta S_{i+1}$$

$$\nabla \Psi^{(m)} \nabla \delta S \equiv \gamma_{2i} (\delta S_{i+1} - \delta S_i) - \alpha_{2i} (\delta S_i - \delta S_{i-1})$$

$$\nabla \frac{\partial \Psi}{\partial S} \delta S \nabla S^{(m)} + \nabla \Psi^{(m)} \nabla \delta S \equiv \alpha_i \delta S_{i-1} + \beta_i \delta S_i + \gamma_i \delta S_{i+1}$$

$$\alpha_i = \alpha_{1i} + \alpha_{2i}, \quad \beta_i = \beta_{1i} + \beta_{2i}, \quad \gamma_i = \gamma_{1i} + \gamma_{2i}$$

Summarizing, we can write:

$$A_i \delta S_{i-1} + B_i \delta S_i + C_i \delta S_{i+1} = E_i \quad (4.5.2n)$$

where

$$A_i = b \alpha_i, \quad B_i = b \beta_i, \quad C_i = b \gamma_i, \quad E_i = S_i^* - b \nabla \Psi^{(m)} \nabla S^{(m)} - S_i^{(m)}$$

The values of the saturation S_i^{m+1} at the next iteration level are assessed using calculated values δS_i :

$$S_i^{m+1} = S_i^m + \delta S_i$$

The calculations are carried out until a stopping criterion is satisfied.

The proposed method has been tested for a set of data for the initial-boundary value test problem with known analytical solution. It was the Burger's equation (see below) which served as a bench mark for this new scheme.

Burger's equation, in one dimension, is of the form:

$$\frac{du}{dt} + u \frac{du}{dx} - \frac{1}{Re} \frac{d^2u}{dx^2} = 0$$

Solution to this equation will be sought in the region $-1 \leq x \leq 1$ for $t > 0$. Initial and boundary conditions are taken to be

$$u_0(x) = u(x, 0) = \begin{cases} 1 & \text{for } -1 < x \leq 0 \\ 0 & \text{for } 0 < x \leq 1 \end{cases} \quad (4.5.2o)$$

$$u(-1, t) = 1, \quad u(1, t) = 0$$

The exact solution of this problem is given by:

$$\mu_e = \frac{\int_{-1}^1 \frac{x-\xi}{t} \exp(-0.5 \cdot Re \cdot F) d\xi}{\int_{-1}^1 \exp(-0.5 \cdot Re \cdot F) d\xi} \quad (4.5.2p)$$

where:

$$F(\xi; x, t) = \int_0^\xi u_b(\xi') d\xi' + 0.5 (x - \xi)^2 / t \quad (4.5.2q)$$

To assure a stability of the solution, an implicit scheme was applied in addition to the dynamic grid approach. Figures 126 - 135 are plots of concentration values vs. dimensionless x values.

The following initial-boundary value problem:

$$u \cdot S_x + S_t = D \cdot S_{xx} \quad (4.5.2r)$$

$$S(0,t) = 1$$

$$S(x,0) = S_0(x)$$

with a known solution:

$$S(x,t) = \frac{1}{2} \left[\operatorname{erfc} \left(\frac{x-ut}{2\sqrt{Dt}} \right) + e^{\frac{ux}{D}} \cdot \operatorname{erfc} \left(\frac{x+ut}{2\sqrt{Dt}} \right) \right] \quad (4.5.2s)$$

served as another test of the dynamic grid and back projection method.

Series of calculations have been carried out and their results are shown in the following Figures 136 - 143. The plot in Figures 136, 138, 140, 142, shows the calculated saturation profile after first time step; whereas, the plot in Figures 137, 139, 141, 143, shows the calculated profile after twenty time steps. From the plots representing the results obtained using either Dynamic Grid or Back Projection method one can notice a good agreement between analytical and numerical solutions. Moreover, both schemes appear to be practically dispersion-free.

While an explicit general finite difference scheme has been used to obtain numerical results plotted in the Figures 136 - 139, the results plotted in the Figures 140 - 143, were obtained by an application of the implicit scheme. In addition, two kinds of grids have been used: dynamic grid (Figures 136, 137, 140, 141), and static grid (Figures 138, 139, 142, 143). Although the use of the explicit scheme caused some fluctuations (see Figure 137) for $0.0 < x < 0.8$, the numerical dispersion is, nevertheless, practically non-existent. By comparing the Figures 136, 137, 140, 141, with the Figure 138, 139, 142, 143, we can conclude that the results obtained by means of dynamic grid are as good as those of static grid (i.e. Back Projection method). Therefore, we suggest to use the latter method for modelling the three dimensional flow because the coding seems to be easier than in the case of the dynamic grid.

4.6 The Solution of the Saturation Equation for Three-Phase Flow

4.6.1 The Finite Difference Formulation

For the sake of simplicity, the proposed method will be demonstrated for one dimensional displacement. Let write the equation (4.6.1h) in more detail:

$$\begin{aligned} S_{1r} &= D_{11} S_{1u} + D_{12} S_{2u} - v_{12} S_{2r} + F_1(S_1, S_2) \\ S_{2r} &= D_{21} S_{1u} + D_{22} S_{2u} - v_{12} S_{1r} + F_2(S_1, S_2) \end{aligned} \quad (4.6.1a)$$

where:

$$F_i(S_{i1}, S_{i2}) = \alpha_{i1}^{(i)} S_{i1}^2 + \alpha_{i2}^{(i)} S_{i1} S_{i2} + \alpha_{i22}^{(i)} S_{i2}^2$$

$$\alpha_{i1}^{(i)} = -\frac{u}{\phi} \frac{\partial \Psi_{i1}}{\partial S_1}, \quad \alpha_{i2}^{(i)} = -\frac{u}{\phi} \left(\frac{\partial \Psi_{i1}}{\partial S_2} + \frac{\partial \Psi_{i2}}{\partial S_1} \right), \quad \alpha_{i22}^{(i)} = -\frac{u}{\phi} \frac{\partial \Psi_{i2}}{\partial S_2}$$

In order to solve the nonlinear system of partial differential equations (4.6.1a), the problem has to be discretized by an approximation of the derivatives, S_{i1} and S_{i2} as well as S_{i1} .

As a results we obtain:

$$(S_{i1}^{n+1} - S_{i1}^n) / \Delta t = \alpha_{i1} S_{i1-1}^{(i)} + \beta_{i1} S_{i1}^{(i)} + \gamma_{i1} S_{i1+1}^{(i)} + F_{i1}$$

$$(S_{i2}^{n+1} - S_{i2}^n) / \Delta t = \alpha_{i2} S_{i2-1}^{(i)} + \beta_{i2} S_{i2}^{(i)} + \gamma_{i2} S_{i2+1}^{(i)} + F_{i2}$$

$$\alpha_k, \beta_k, \gamma_k, F \text{ are functions of } S_{k-1}^{(i)}, S_k^{(i)}, S_{k+1}^{(i)} \quad (k=1,2)$$

Two cases may be considered:

Case A - explicit scheme ($1 = n$)

Case B - implicit scheme ($1 = n+1$)

4.6.2 The Back Projection Method for Three-Phase Flow

The method is based on the Modified Method of Characteristics (MMC) proposed by Wheeler *et al.* (1988). According to MMC method, the hyperbolic part $uS_x + S_t$ of the differentiation is discretized by forward finite differences; whereas, the diffusion term is approximated by standard finite differences on the nonuniform grid. Time steps are taken in the direction of the characteristic lines of the hyperbolic part of the differential operator.

Marching along the characteristics is the main feature of the method. It reduces the numerical dispersion significantly and allows bigger time steps than standard finite element methods do. Since a fine spatial

grid, which is adapted at every time step is maintained at all times in the neighborhood of the steep front, the simulation of the movement of this front is very precise and almost free from numerical dispersion.

The MMC method, however, cannot be applied to three-phase flow here one has to do with two fronts moving independently of each other.

We propose to apply the Back Projection Method generalized so that to handle more than one moving front. The proposed method may be imposed either on a static or dynamic grid. Let illustrate the concept using following schematic grid diagrams (Figures 144 and 145).

If $x_1^{(n)}$ is a position of a grid point concerning the saturation front of phase 1 at the $t^{(n)}$ time, this point will move to a new position:

$$x_1^{(n+1)} = x_1^{(n)} + v_{11} \cdot \Delta t^{(n)} \quad (4.6.2a)$$

for the time $t^{(n+1)}$.

Having known the position of the front 1 at the time $t^{(n+1)}$ we can easily determine a position of a point concerning the front of the phase 2, by solving the following equation (derived from a request $x_1^{(n+1)} = x_2^{(n+1)}$):

$$x_2^{(n)} = x_1^{(n)} + (v_{11} - v_{22}) \cdot \Delta t^{(n)} \quad (4.6.2b)$$

where:

$$v_{11} = v_{11}(S_1(x_1^{(n)}), S_2(x_1^{(n)})) \quad (4.2.6c)$$

$$v_{22} = v_{22}(S_1(x_2^{(n)}), S_2(x_2^{(n)})) \quad (4.6.2d)$$

In the case of a static grid (Figure 11), we have to find the positions of points $x_1^{(n)}$, $x_2^{(n)}$ will move to the point $x_1^{(n+1)}$ after $\Delta t^{(n)}$ time. In a word, we seek position of a grid point at the old time level $t^{(n)}$ knowing the position of a grid point at the new time level $t^{(n+1)}$ (hence, the terminology Back Projection).

The values of $x_1^{(n)}$ and $x_2^{(n)}$ are determined from the system of equations:

$$x_1^{(n+1)} = x_1^{(n)} + v_{11} \cdot \Delta t^{(n)}$$

$$x_2^{(n+1)} = x_2^{(n)} + v_{22} \cdot \Delta t^{(n)}$$

$$x_1^{(n+1)} = x_2^{(n+1)}$$

where:

$$v_{11} = v_{11}(S_1(x_1^{(n)}), S_2(x_1^{(n)}))$$

$$v_{22} = v_{22}(S_1(x_2^{(n)}), S_2(x_2^{(n)}))$$

5.0 CONCLUSIONS

The preliminary work on gravity assisted immiscible gas injection fully justifies the continuation of the project.

The efficiency of the waterflood prior to gas injection is an important parameter for the success of the gas injection step.

Gravity assisted immiscible gas injection can be very successful in oil wet, mixed wet, or water wet systems.

Presence of vugs does not seem to be detrimental to the process. However, the presence of fractures has a detrimental effect in the recovery efficiency.

The reservoir seems to be of mixed wettability, with the matrix preferentially water wet.

A method for the calculation of capillary pressures in three phase systems was presented.

Methods for measurement of wettability, capillary pressure and permeability of heterogeneous systems were presented. Different pore size systems were identified in the measurement of capillary pressures.

Novel algorithms for the modeling of the gravity assisted immiscible gas injection process are also presented.

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8.0 TABLES

TABLE 1: SUMMARY OF RESULTS FOR THE SAND AND GLASS BEAD COLUMNS

Column Type	Porosity Fraction	Initial Oil Saturation (%Pv)	Oil Recovery by Wflooding (%OOIP)	Oil Saturation after Wflooding (%Pv)	Oil Recovery by GDrainage (%OIP)	Oil Saturation after GDrainage (%Pv)	Average Flowrate of Liquid (cc/hr)
SP 10x100 Water-wet	0.406	68.1	76.7	15.9	39.1	9.7	3
SP 5x50 Oil-wet	0.384	83.5	70.7	24.5	33.1	16.4	1.5
GB 5.50 Oil-wet #1	0.396	95.0	76.8	22.0	97.9	0.4	1.2
GB 5x50 Oil-wet #2	0.39	93.2	83.9	15.0	13.9	12.9	0.9
GB 5x50 Oil-wet #3	0.356	88.5	59.6	35.7	67.6	11.6	0.7
GB 5.50 Mixed-wet	0.369	78.6	76.3	18.6	81.5	3.4	0.7
GB 5x50 Water-Wet	0.371	79.9	79.1	16.7	78.7	3.6	0.9

GB: Glass Bead Column
SP: Sand Pack Column

Oil viscosity = 2.96 mPa.sec
Water viscosity = 1.00 mPa.sec
Waterflood injection rate = 60 cc/hr

**TABLE 2: SUMMARY OF THE PETROPHYSICAL PROPERTIES
RAINBOW F POOL**

Well Location	Sample Number	Porosity (%)	Permeability to Air (mD)	Permeability to Brine (mD)
9-28	1a	6.4	70.47	44.43
9-28	2a	8.7	2337.71	820.08
9-28	3a	8.1	35.67	28.08
9-28	8a	9.1	N/A	N/A
9-28	10a	12.9	N/A	N/A
9-28	11a	8.9	2.27	1.3
9-28	14a	11.3	12.49	8.38
6-6	1a	12.1	91.33	59.64
6-6	2a	11.7	18.08	5.97
6-6	4a	9.6	9.56	3.61
6-6	5a	15.1	1208.13	698.81

N/A not available (sample broke in the ultracentrifuge).

**TABLE 3: SAMPLE IDENTIFICATION SUMMARY
RAINBOW F POOL**

Well Location	Sample Number	Depth (m)	Length (cm)	Diameter (cm)
9-28	1a	1816.60	4.62	3.72
9-28	2a	1817.00	4.56	3.72
9-28	3a	1822.45	4.56	3.68
9-28	8a	1827.90	4.58	3.73
9-28	10a	1835.00	4.62	3.73
9-28	11a	1839.07	4.58	3.70
9-28	14a	1840.70	4.51	3.71
6-6	1a	1810.36	4.20	3.71
6-6	2a	1812.13	4.56	3.72
6-6	4a	1822.28	4.10	3.73
6-6	5a	1824.00	4.56	3.73

TABLE 4: WETTABILITY RESULTS OF THE COMBINED AMOTT AND USBM TESTS FOR THE RAINBOW F POOL PRESERVED SAMPLES USING F POOL OIL

Sample #/LSD	Fractional Porosity	Amott wettability Index to water	Amott wettability Index to oil	USBM Index	Wettability Tendency
1A/9-28	0.064	0.375	0.579	0.492	fractional
2A/9-28	0.087	0.561	0.355	0.444	fractional
3A/9-28	0.081	0.400	0.259	1.170	fractional
8A/9-28	0.091	0.348	0.730	0.503	fractional
10A/9-28	0.129	0.375	0.459	1.019	fractional
11A/9-28	0.089	0.545	0.308	0.070	fractional
14A/9-28	0.113	0.328	0.333	0.116	fractional
1A/6-6	0.121	0.430	0.641	-0.121	fractional
2A/6-6	0.117	0.605	0.286	-0.406	fractional
4A/6-6	0.096	0.643	0.667	1.158	fractional
5A/6-6	0.151	0.615	0.196	0.331	fractional

Tests were performed at 87°C.

TABLE 5: SATURATION RESULTS OF THE COMBINED AMOTT AND CENTRIFUGE TESTS FOR THE
RAINBOW F POOL PRESERVED SAMPLES USING F POOL OIL

Sample #/LSD	Porosity* (Frac)	Initial** water sat. (Frac)	Water sat. after spin to swi (Frac)	Water sat. after imbibition (Frac)	Water sat. after forced imbibition (Frac)	Water sat. spont drainage (Frac)	Water sat. after forced drainage (Frac)	Water sat. after onestep forced imbibition (Frac)	Oil Recovery by Water Imbibition (% OOIP)
1A/9-28	0.064	0.6886	0.2980	0.3917	0.5480	0.3761	0.2511	0.5636	42
2A/9-28	0.087	0.8649	0.1905	0.5626	0.8533	0.5974	0.1323	0.7486	71
3A/9-28	0.081	0.8576	0.1909	0.4473	0.8320	0.6525	0.1397	0.7166	67
8A/9-28	0.0912	0.8638	0.0781	0.2686	0.6257	0.3043	0.1852	0.7210	66
10A/9-28	0.129	0.7652	0.0806	0.3114	0.6960	0.4191	0.1114	0.6114	56
11A/9-28	0.089	0.8127	0.1582	0.4991	0.7832	0.6014	0.1923	0.7604	70
14A/9-28	0.113	0.7326	0.1053	0.3053	0.7144	0.5508	0.2235	0.7690	70
1A/6-6	0.121	0.7424	0.0606	0.3697	0.7788	0.3242	0.0697	0.7970	78
2A/6-6	0.117	0.9157	0.2261	0.6226	0.8812	0.7088	0.2778	0.8812	84
4A/6-6	0.096	0.5854	0.1203	0.3296	0.4459	0.2133	0.0971	0.3878	32
5A/6-6	0.151	0.8152	0.1152	0.5418	0.8085	0.6618	0.0619	0.8952	89

* does not include surface vugs.

** at native-state after evacuating under formation brine.

TABLE 6: RESULTS OF CENTRIFUGE AIR INJECTION AFTER WATER IMBIBITION FOR THE
RAINBOW F POOL PRESERVED SAMPLES USING F POOL OIL

Sample #/LSD	Oil sat. before air injection (Frac)	Oil sat. after air injection (Frac)	Oil recovery by air injection (% OiP)	Oil recovery by air injection (% OOIP)
1A/9-28	0.4364	0.4052	7	4
2A/9-28	0.2514	0.1933	23	7
3A/9-28	0.2834	0.2193	23	7
8A/9-28	0.2790	0.1600	43	15
10A/9-28	0.3886	0.1963	49	22
11A/9-28	0.2396	0.1714	28	8
14A/9-28	0.2310	0.1401	39	12
1A/6-6	0.2030	0.0667	67	15
2A/6-6	0.1188	0.0757	36	6
4A/6-6	0.6122	0.4960	19	13
5A/6-6	0.1048	0.0381	64	7

**TABLE 7: WETTABILITY RESULTS OF THE COMBINED AMOTT AND USBM TESTS FOR
THE RAINBOW F POOL RESTORED-STATE SAMPLES USING F POOL OIL**

Sample #/LSD	Fractional Porosity	Amott wettability Index to water	Amott wettability Index to oil	USBM Index	Wettability Tendency
2A/9-28	0.087	0.286	0.310	-0.324	fractional
3A/9-28	0.081	0.286	0.410	1.288	fractional
10A/9-28	0.129	0.237	0.500	0.696	fractional

Samples aged under oil at S_{wir} for 40 days.

Tests conducted at 87°C.

TABLE 8: SATURATION RESULTS OF THE AMOTT AND CENTRIFUGE TESTS
FOR THE RAINBOW F POOL RESTORED-STATE SAMPLES USING F POOL OIL

Sample #/LSD	Porosity (Frac)	Initial water sat. (Frac)	Water sat. after spin to swl. (Frac)	Water sat. after spont imbibition (Frac)	Water sat. after forced imbibition (Frac)	Water sat. spont drainage (Frac)	Water sat. after forced drainage (Frac)	Water sat. after onestep forced imbibition (Frac)	Oil Recovery by Water Imbibition (% OOIP) (Frac)
2A/9-28	0.087	1.00	0.1250	0.3472	0.9028	0.7222	0.3194	0.8750	82
3A/9-28	0.081	1.00	0.1290	0.3548	0.9194	0.6613	0.2903	0.8548	80
10A/9-28	0.129	1.00	0.1848	0.3116	0.7192	0.4293	0.1395	0.7736	74

Samples aged under oil at S_{wir} for 40 days.

**TABLE 9: RESULTS OF CENTRIFUGE AIR INJECTION AFTER WATER IMBIBITION FOR THE RAINBOW F
POOL RESTORED SAMPLES USING F POOL OIL**

Sample #/LSD	Oil sat. before air injection (Frac)	Oil sat. after air injection (Frac)	Oil recovery by air injection (% OIP)	Oil recovery by air injection (% OOIP)
2A/9-28	0.1250	0.0556	56	10
3A/9-28	0.1452	0.0645	56	11
10A/9-28	0.2264	0.1359	40	11

TABLE 10: WETTABILITY RESULTS OF THE COMBINED AMOTT AND USBM TESTS FOR THE BERE A AND BAKER DOLOMITE
USING F POOL OIL

Sample ID	Test Condition	Fractional Porosity	Amott wet. Index to water	Amott wet. Index to oil	USBM Index	Wettability Tendencies
Berea 1	performed @ 87°C	0.230	0.932	0.091	0.257	strongly water wet
Berea 2	performed @ 87°C	0.228	0.960	0.094	0.894	strongly water wet
Berea 3	performed @ 87°C	0.232	0.925	0.085	0.948	strongly water wet
Dolomite 1	performed @ 87°C	0.218	0.333	0.000	0.289	water wet
Dolomite 2	performed @ 87°C	0.223	0.467	0.000	0.242	water wet, weak
Dolomite 3	performed @ 87°C	0.229	0.263	0.000	0.544	water wet
Dolomite 4	performed @ 87°C	0.230	1.000	0.058	>1	strongly water wet
Dolomite 5	performed @ 87°C	0.239	0.876	0.058	>1	strongly water wet
Dolomite 6	performed @ 87°C	0.231	0.914	0.056	>1	strongly water wet
Dolomite 1	Amott @ 40°C, centrifuge @ 87°C	0.230	0.364	n/a	n/a	data insufficient
Dolomite 2	Amott @ 40°C, centrifuge @ 87°C	0.217	0.384	n/a	n/a	data insufficient
Dolomite 3	Amott @ 40°C, centrifuge @ 87°C	0.225	0.338	n/a	n/a	data insufficient
Berea 1	performed @ 87°C	0.224	0.839	n/a	n/a	data insufficient
Berea 3	performed @ 87°C	0.227	0.845	n/a	n/a	data insufficient

TABLE 11: SATURATION RESULTS OF THE AMOTT AND CENTRIFUGE TESTS FOR THE BEREA SANDSTONE AND BAKER
DOLomite USING F POOL OIL

Sample #	Porosity	Initial water sat.	Water sat. after spin down to swl. (Frac)	Water sat. after spont imbibition (Frac)	Water sat. after forced imbibition (Frac)	Water sat. after spont drainage (Frac)	Water sat. after forced drainage (Frac)	Water sat. after onestep forced imbibition (Frac)	Oil recovery by water imbibition (% OOIP)
Berea 1	0.230	1.0000	0.1614	0.6410	0.6758	0.6236	0.1014	0.7133	68
Berea 2	0.228	1.0000	0.1493	0.6797	0.7018	0.6443	0.0919	0.7544	73
Berea 3	0.232	1.0000	0.1568	0.7007	0.7226	0.6695	0.1004	0.8135	79
Dolomite 1	0.218	1.0000	0.1653	0.2467	0.4096	0.4096	0.0000	n/a	29
Dolomite 2	0.223	1.0000	0.1755	0.3184	0.4817	0.4817	0.0246	n/a	25
Dolomite 3	0.229	1.0000	0.1653	0.2586	0.5248	0.5248	0.0381	n/a	43
Dolomite 4	0.230	1.0000	0.1409	0.5962	0.5962	0.5618	0.0034	n/a	53
Dolomite 5	0.239	1.0000	0.1228	0.5656	0.6283	0.5949	0.0519	n/a	58
Dolomite 6	0.231	1.0000	0.1416	0.5965	0.6394	0.6051	0.0257	n/a	58
Dolomite 1	0.230	1.0000	0.1991	0.3517	0.6187	n/a	n/a	n/a	52
Dolomite 2	0.217	1.0000	0.1123	0.3187	0.6490	n/a	n/a	n/a	48
Dolomite 3	0.225	1.0000	0.1235	0.2988	0.6418	n/a	n/a	n/a	59
Berea 1	0.224	1.0000	0.1289	0.4774	0.5444	n/a	n/a	n/a	48
Berea 3	0.227	1.000	0.1080	0.4737	0.5406	n/a	n/a	n/a	48

**TABLE 12: RESULTS OF CENTRIFUGE AIR INJECTION AFTER WATER IMBIBITION FOR THE
BEREA SANDSTONE & BAKER DOLOMITE USING F POOL OIL**

Sample #	Oil Saturation before air injection	Oil Saturation after air injection	Oil recovery by air injection (% OIP)	Oil recovery by air injection (% OOIP)
Berea 1	0.2867	0.1562	46	15
Berea 2	0.2456	0.1131	54	15
Berea 3	0.1865	0.0552	70	15
Dolomite 1	0.3813	0.1525	60	18
Dolomite 2	0.3510	0.1239	65	26
Dolomite 3	0.3582	0.0914	74	30

**TABLE 13: WETTABILITY RESULTS OF THE COMBINED AMOTT AND USBM TESTS
FOR THE BEREA SANDSTONE SAMPLES USING BAYOL SYNTHETIC OIL**

Sample #/temp.	Test Condition	Fractional Porosity	Amott wettability Index to water	Amott wettability Index to oil	Wettability Tendency
Berea 1/25°C	$T = T_{\text{room}}$	0.228	0.741	0.008	strongly water wet
Berea 2/25°C	$T = T_{\text{room}}$	0.228	0.758	0.000	strongly water wet
Berea 3/25°C	$T = T_{\text{room}}$	0.231	0.754	0.000	strongly water wet
Berea 1/87°C	$T = 87^{\circ}\text{C}$	0.230	0.776	0.000	strongly water wet
Berea 2/87°C	$T = 87^{\circ}\text{C}$	0.230	0.766	0.016	strongly water wet
Berea 3/87°C	$T = 87^{\circ}\text{C}$	0.230	0.754	0.031	strongly water wet

* Experiment repeated with the first set of samples.

TABLE 14: SATURATION RESULTS OF THE AMOTT AND CENTRIFUGE TESTS FOR THE
BEREA SANDSTONE SAMPLES USING BAYOL SYNTHETIC OIL

Sample #/temp.	Porosity (Frac)	Initial water sat. (Frac)	Water sat. after spln to swi (Frac)	Water sat. after spont imbibition (Frac)	Water sat. after forced imbibition (Frac)	Water sat. after spont drainage (Frac)	Water sat. after forced drainage (Frac)	Water sat. after onestep forced imbibition (Frac)	Oil Recovery by Water Imbibition (% OOIP)
Berea 1/25°C	0.228	1.00	0.1238	0.5013	0.6330	0.6287	0.0948	0.6435	61
Berea 2/25°C	0.228	1.00	0.1265	0.5425	0.6752	0.6752	0.1442	0.6531	59
Berea 3/25°C	0.231	1.00	0.1525	0.5557	0.6871	0.6871	0.1394	0.6652	61
Berea 1/87°C	0.230	1.00	0.1087	0.5609	0.6913	0.6913	0.1400	0.7270	68
Berea 2/87°C	0.230	1.00	0.1213	0.5518	0.6837	0.6749	0.1257	0.6968	65
Berea 3/87°C	0.230	1.00	0.1205	0.5602	0.7036	0.6860	0.1363	0.7080	66

**TABLE 15: RESULTS OF CENTRIFUGE AIR INJECTION AFTER WATER IMBIBITION FOR THE BEREA
SAND SAMPLES USING BAYOL USING SYNTHETIC OIL**

Sample #/temp.	Oil sat. before air injection (Frac)	Oil sat. after air injection (Frac)	Oil recovery by air injection (% OIP)	Oil recovery by air injection (% OOIP)
Berea 1/25°C	0.3565	0.1370	62	24
Berea 2/25°C	0.3469	0.1035	70	28
Berea 3/25°C	0.3348	0.0934	73	28
Berea 1/87°C	0.2730	0.0339	87	28
Berea 2/87°C	0.3032	0.0395	87	30
Berea 3/87°C	0.2920	0.0281	90	31

TABLE 16: SUMMARY OF RESULTS FOR THE MICROMODELS

Model Type	Drainage Type	Initial Oil Saturation (%Pv)	Oil Recovery by Wflooding (%OOIP)	Oil Saturation after Wflooding (%Pv)	Oil Recovery by GDrainage (%OOIP)	Oil Saturation after GDrainage (%Pv)	Average Flowrate of Liquid (cc/hr)
H2A Water-wet	MSTEP	76.8	18.3	62.7	35.9	40.2	0.0007
H2B Water-wet	MSTEP	72.6	12.6	63.4	32.5	42.8	0.0002
D2A Water-wet	MSTEP	77.1	53.1	36.2	31.6	24.7	0.0006
D2B Water-wet	SSTEP	83.8	55.3	37.5	22.2	29.1	N/A
D2C Oil-wet	SSTEP	84.2	73.3	22.5	15.4	19.0	19.5
D1A Water-wet	MSTEP	76.2	22.5	59.1	49.4	29.9	0.0001
S1A Oil-wet	SSTEP	95.3	65.5	32.9	0	32.9	3.4
S1B Oil-wet	SSTEP	78.1	68.0	25.0	4.5	23.9	3.6
S1C Water-wet	SSTEP	65.7	91.3	5.7	0	5.7	1.1

MSTEP: Multi-step
SSTEP: Single-step

Oil Viscosity = 2.96 mPa.sec
Water Viscosity = 1.00 mPa.sec
Waterflood Injection rate = 0.01 cc/hr
N/A = Not Available

TABLE 17: PVT Properties

P	RS	BO	EG	VISO	VISG
100.700	0.0	1.000	1.0	1.0400000	0.0080000
1820.700	16.100	1.15000	14.700	0.9750000	0.0096000
3543.700	32.050	1.20700	28.300	0.9100000	0.0112000
6991.700	66.050	1.29500	55.700	0.8300000	0.0140000
13886.700	113.200	1.43500	110.400	0.6950000	0.0189000
17333.000	138.000	1.50000	137.600	0.6410000	0.0208000
20780.700	165.600	1.56500	164.800	0.5940000	0.0228000
27675.700	226.000	1.69500	219.500	0.5100000	0.0268000
34570.700	288.000	1.82700	274.300	0.4490000	0.0309000
62149.700	531.000	2.35700	461.300	0.2030000	0.0470000



The relative permeability data were as follows (for water):

TABLE 18: Relative Permeability Data		
SW	KRW	KROW
0.30	0.00	0.50
0.40	0.03	0.30
0.50	0.05	0.20
0.60	0.12	0.12
0.65	0.18	0.18
0.70	0.26	0.05
1.00	1.00	0.00

and (for gas):

SL	KRG	KROG
0.00	0.50	0.00
0.10	0.50	0.02
0.20	0.50	0.03
0.30	0.50	0.05
0.40	0.30	0.08
0.50	0.20	0.12
0.60	0.12	0.20
0.65	0.08	0.30
0.70	0.05	0.50
1.00	0.00	0.50

And finally, the capillary pressure curves were approximated by the values taken from Table 3:

TABLE 19: Capillary Pressure Data	
SW	PCOW (kPa)
0.30	87.15
0.40	76.67
0.50	66.19
0.60	55.71
0.65	50.47
0.70	45.23
1.00	13.79
SL	PCGO (kPa)
0.00	118.59
0.10	108.11
0.20	97.63
0.30	87.15
0.40	76.67
0.50	66.19
0.60	55.70
0.65	50.47
0.70	45.23
1.00	13.79

**TABLE 20: The methods applied to obtain the results
plotted in Figures 136 - 143**

	Dynamic Grid	Static Grid
explicit scheme	136, 137	138, 139
implicit scheme	140, 141	142, 143

TABLE 21: SUMMARY OF CONTACT ANGLE AND INTERFACIAL TENSION TESTS

Interfacial Tension Data								
Fluid 1	Fluid 2	Temp (°C)	Pressure (Psig)	Contact Angle	Bubble Volume (cm ³)	ρ^1 (g/cm ³)	ρ^2 (g/cm ³)	IFT (dyn/cm)
brine	H ₂ S-free oil	87	2200	28.4	0.00766	1.101	0.706	20.4
brine	H ₂ S-rich oil	87	2200	31.0	0.01516	1.041	0.690	35.1
brine	H ₂ S-free gas	87	2200	28.8	0.00508	1.023	9.190	29.3
brine	H ₂ S-rich gas	87	2200	30.5	0.00780	1.033	0.120	48.3

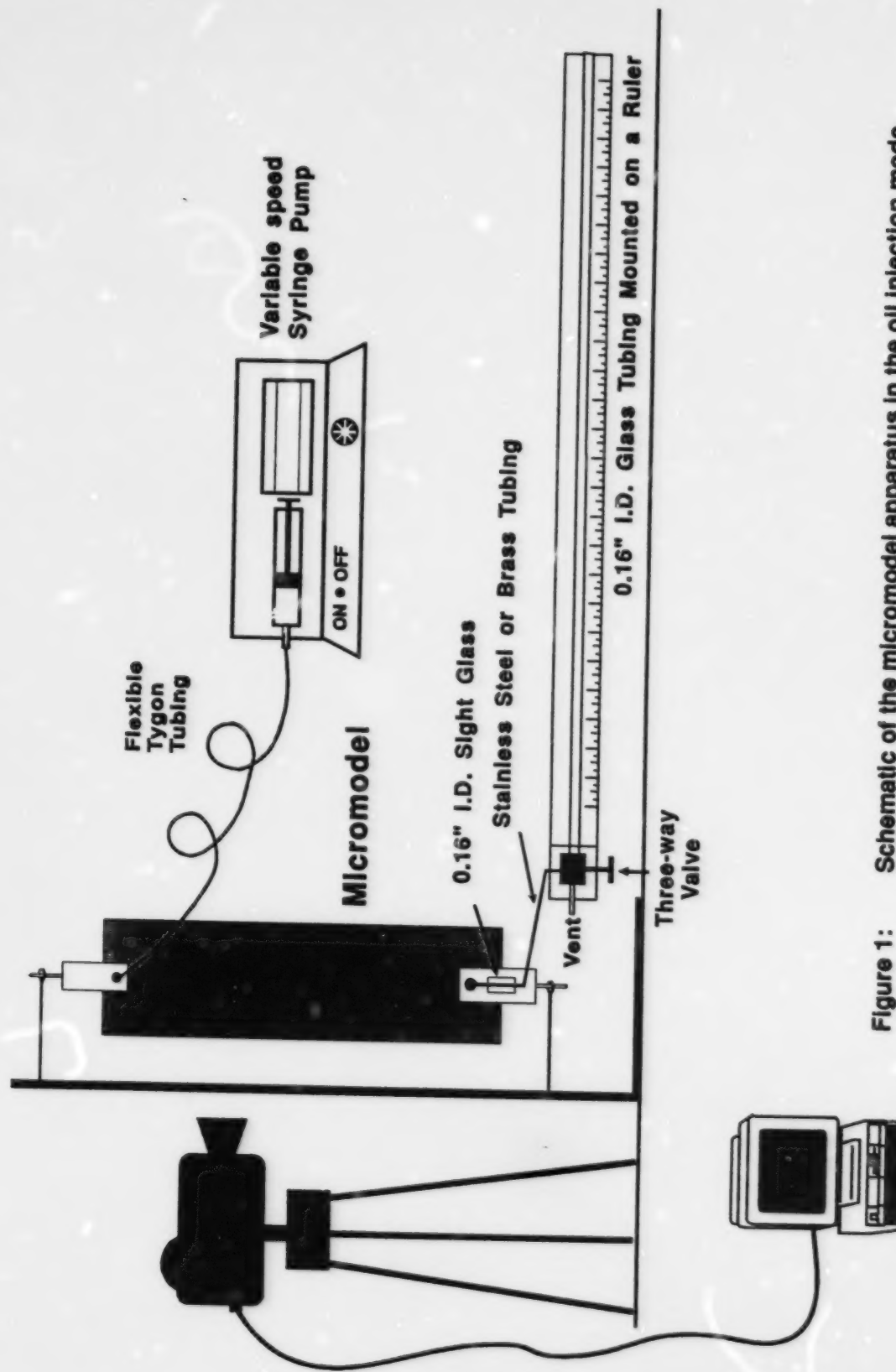


Figure 1: Schematic of the micromodel apparatus in the oil injection mode.

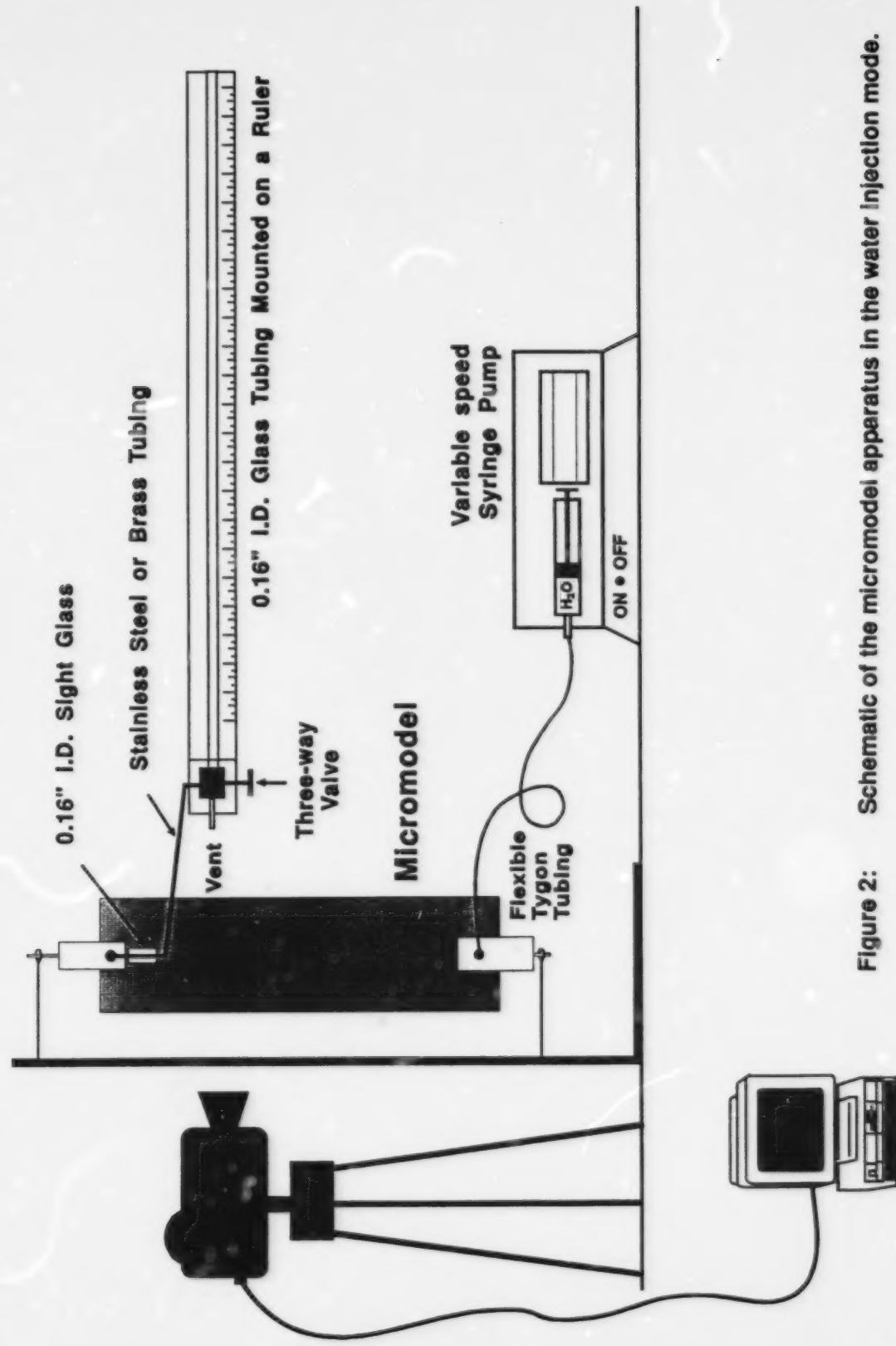


Figure 2: Schematic of the micromodel apparatus in the water injection mode.

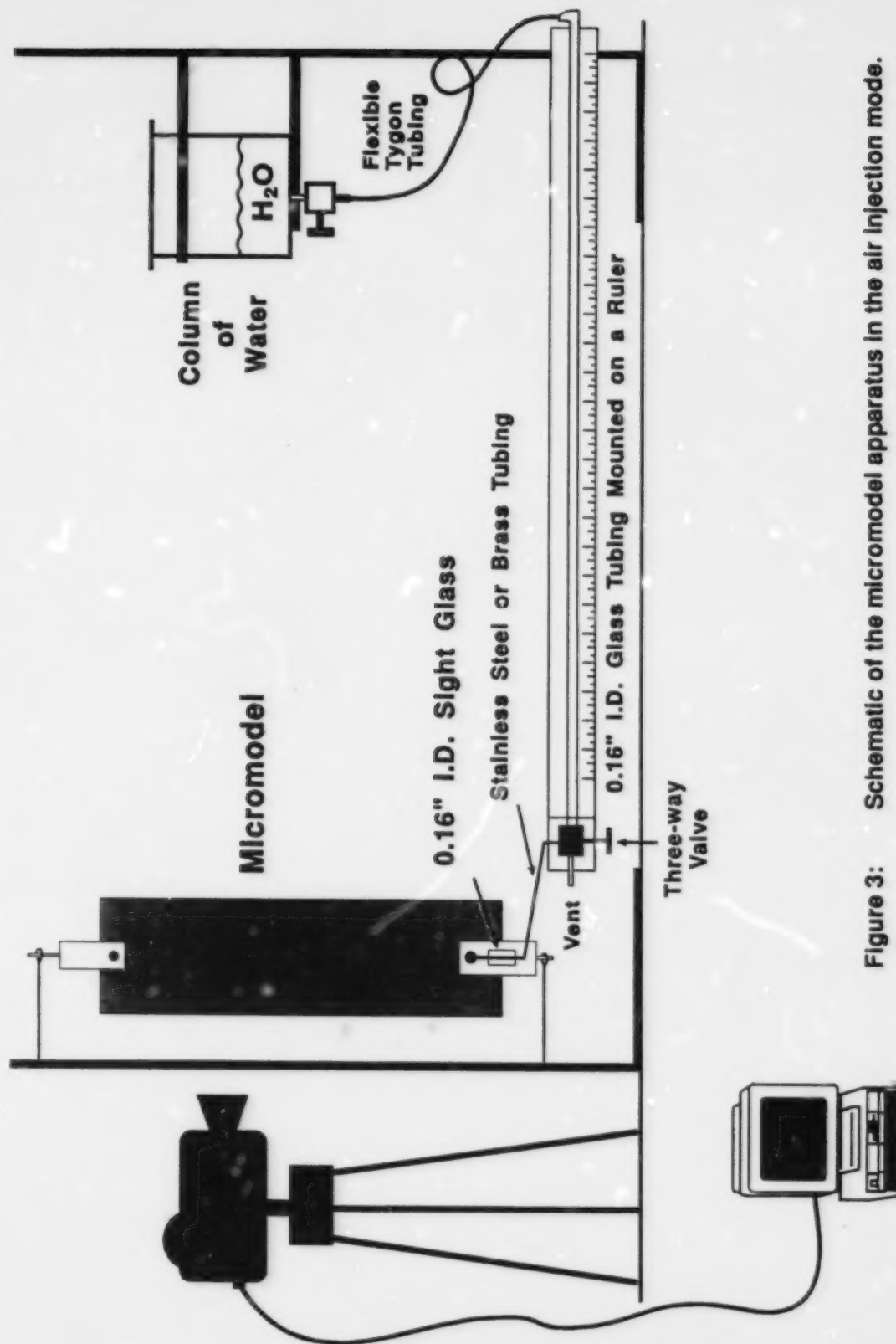


Figure 3: Schematic of the micromodel apparatus in the air injection mode.

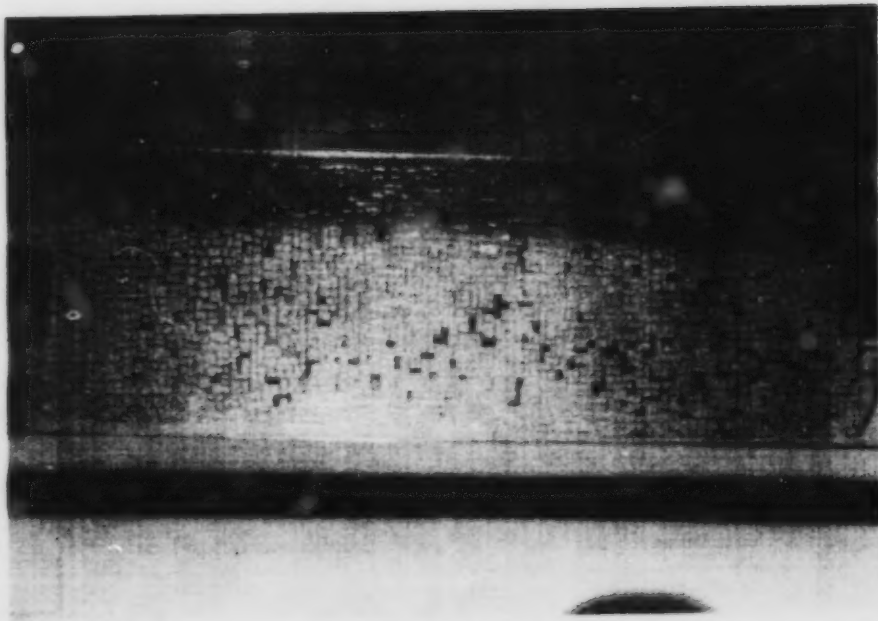


Figure 4: Photograph of micromodel H2.

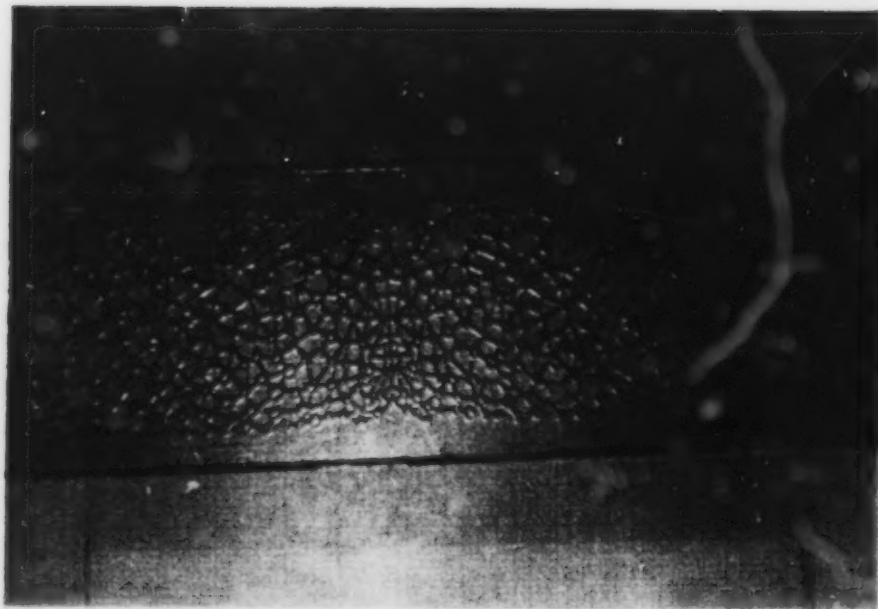


Figure 5: Photograph of micromodel D2.

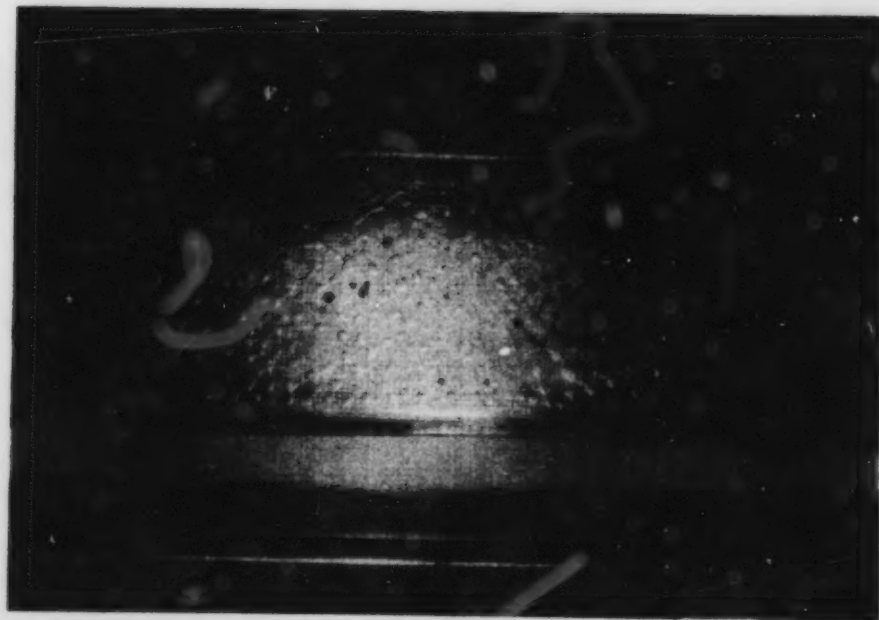


Figure 6: Photograph of micromodel D1.



Figure 7: Photograph of micromodel S1.

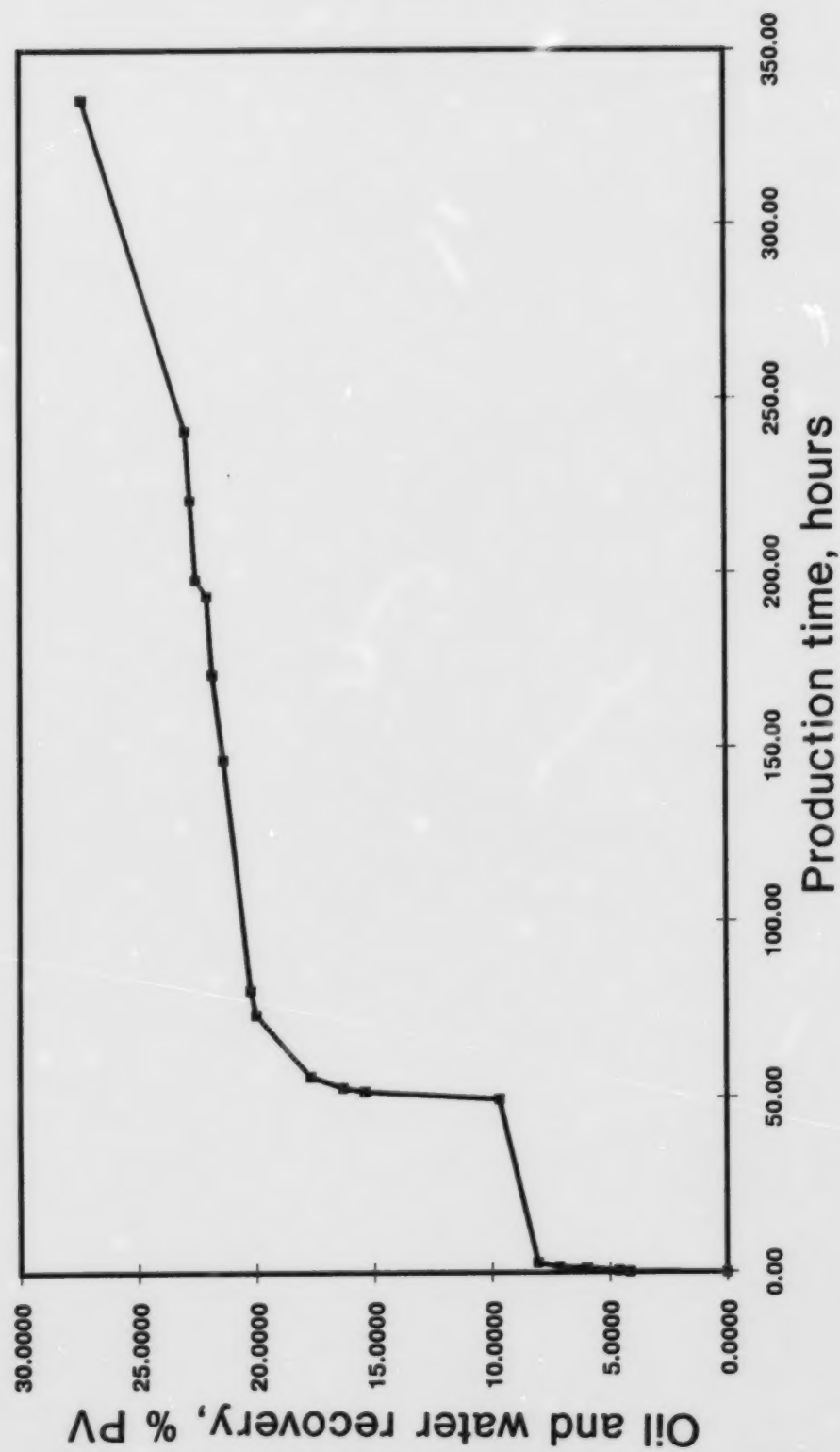


Figure 8: Liquid production curve for gas Injection in micromodel H2A.

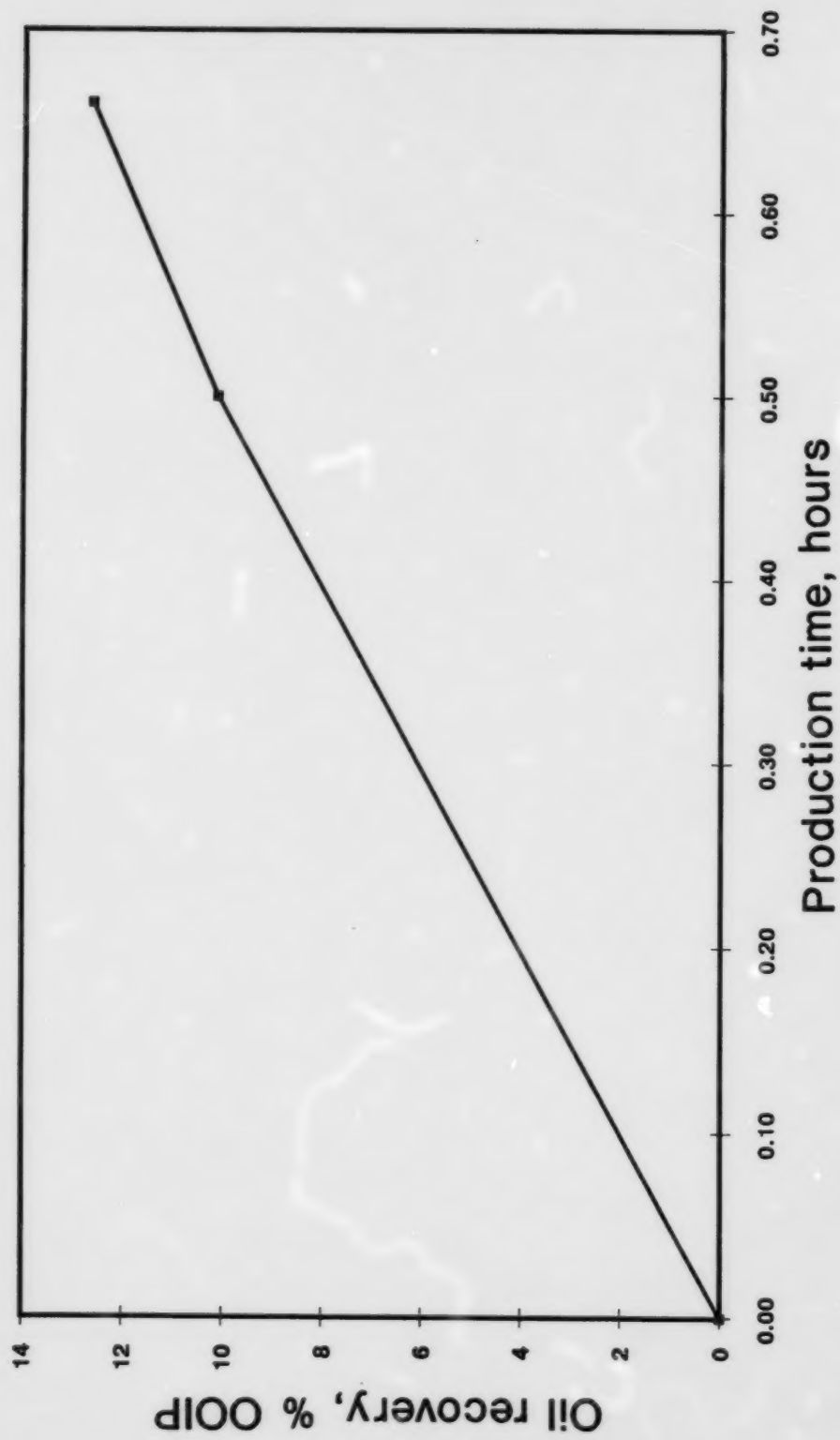


Figure 9: Oil recovery during waterflood of micromodel H2B.

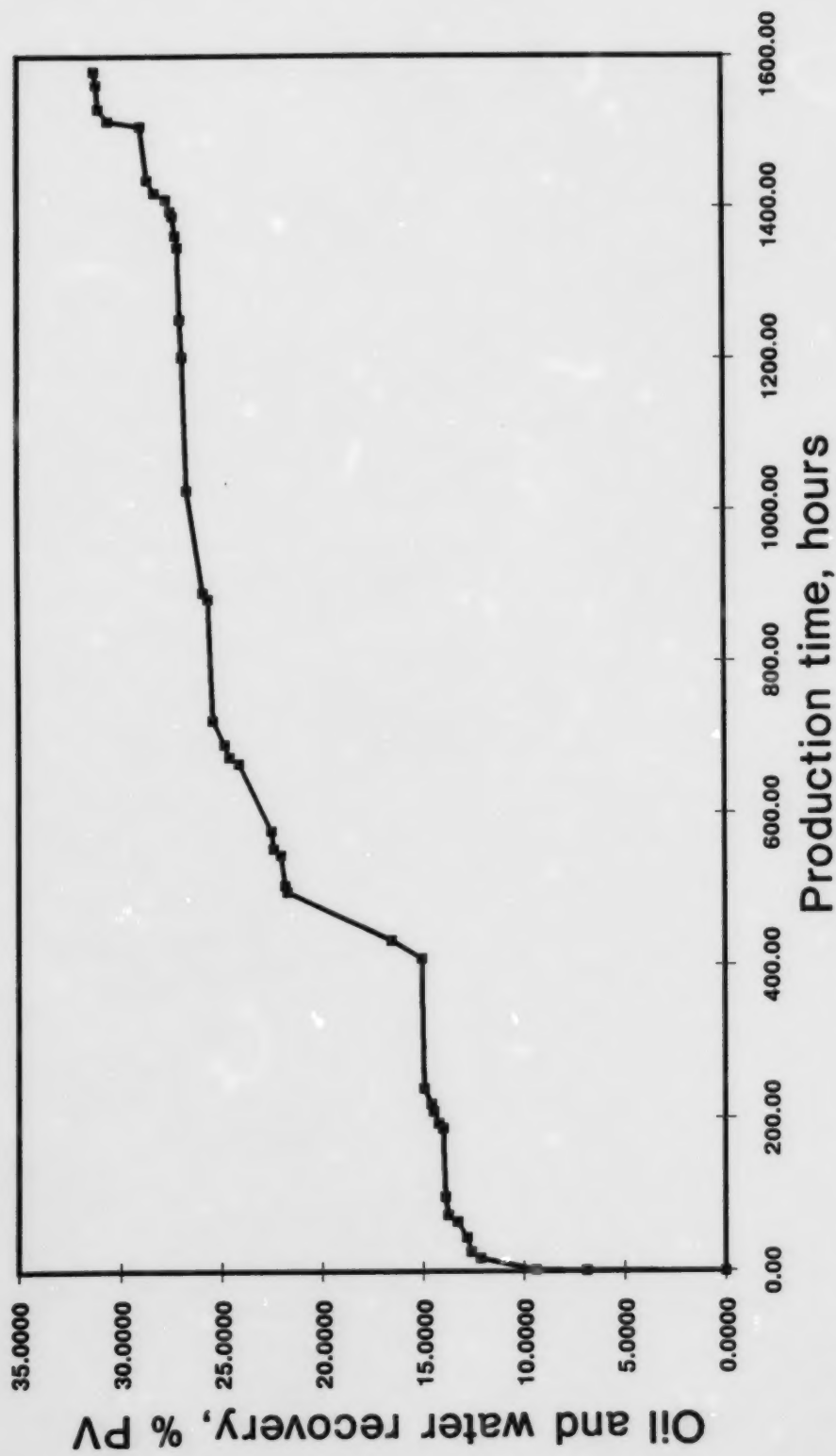


Figure 10: Liquid production curve for gas injection in micromodel H2B.



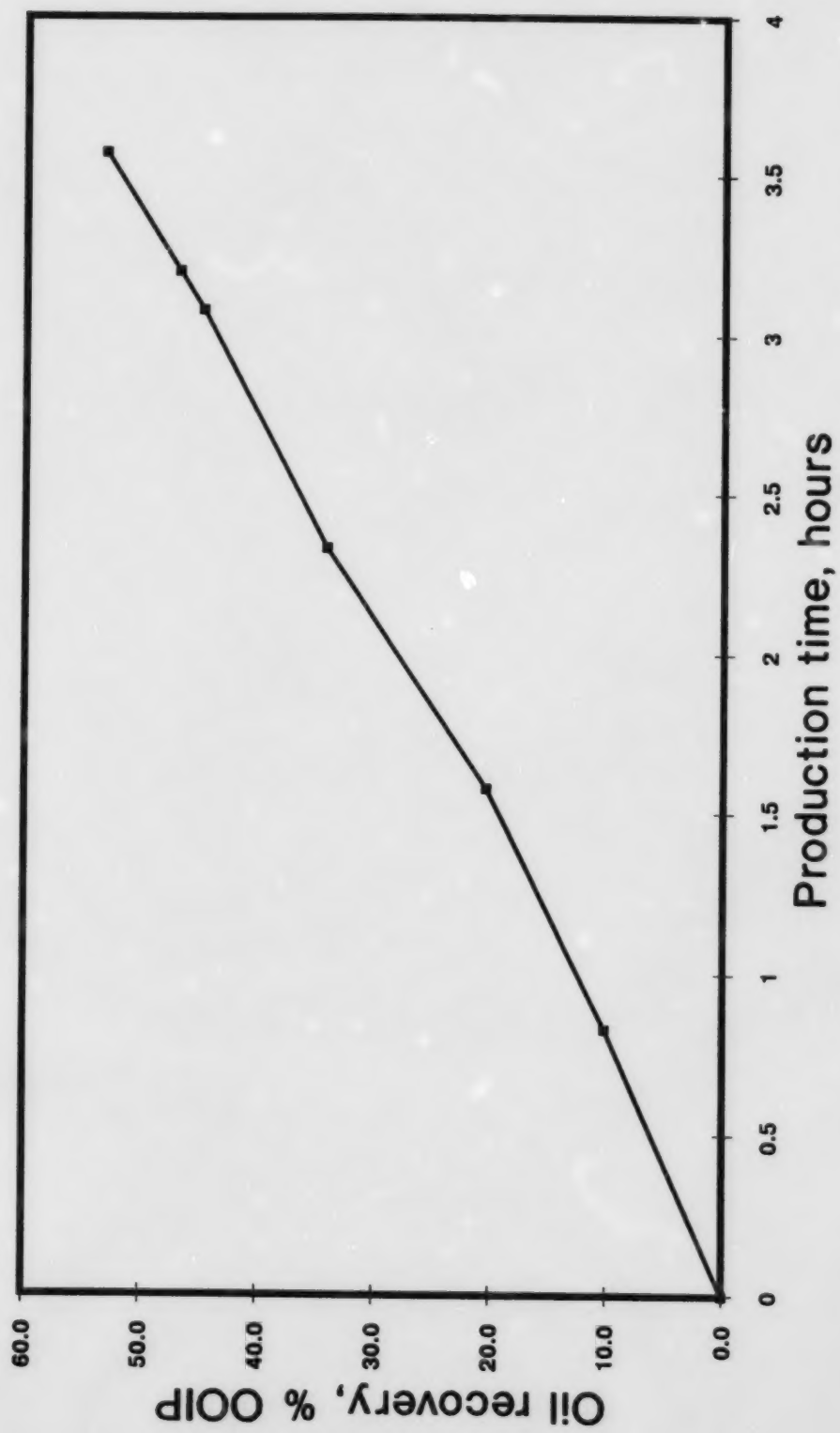


Figure 11: Oil recovery during waterflood of micromodel D2A.

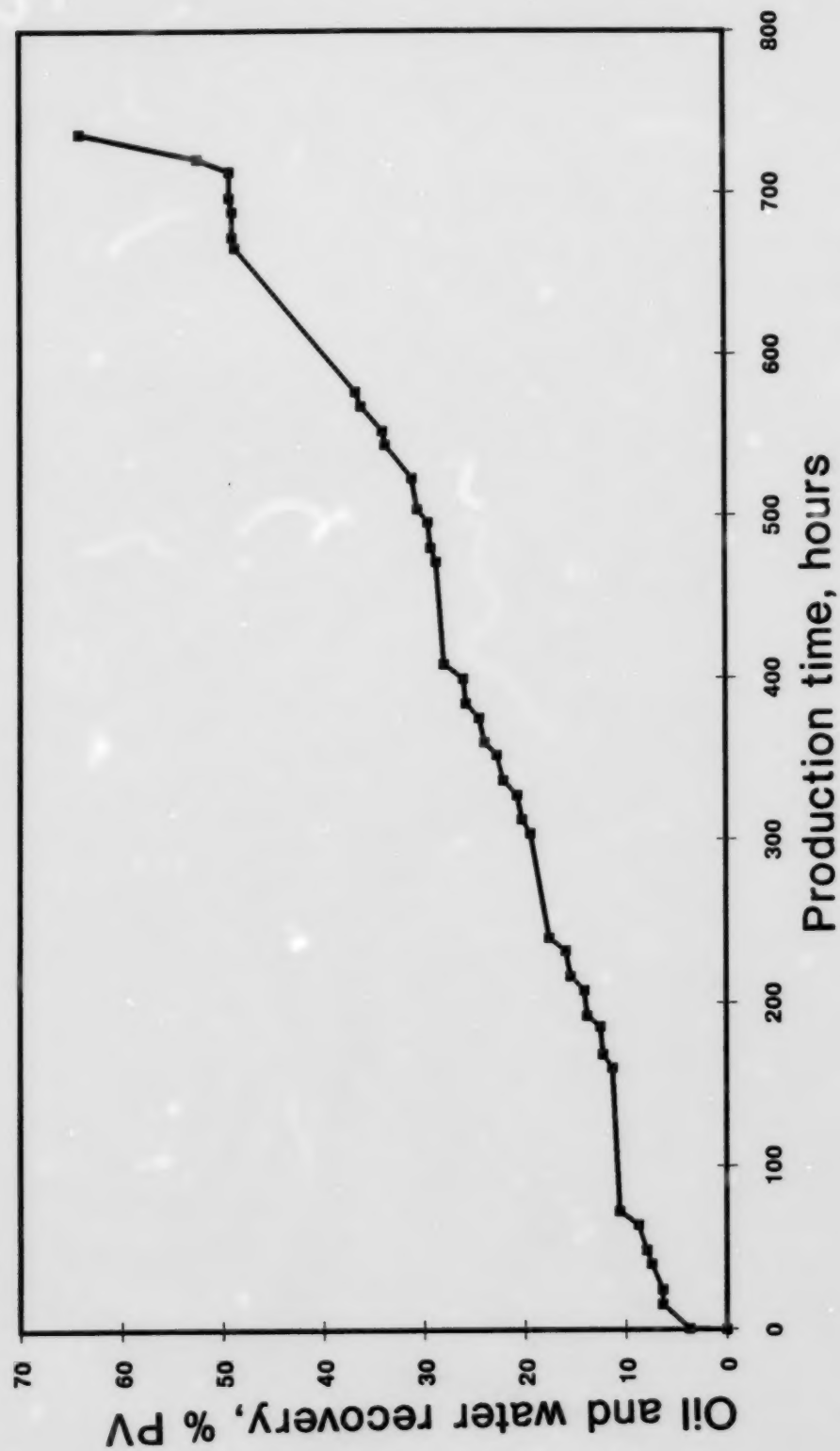


Figure 12: Liquid production curve for gas injection in micromodel D2A.

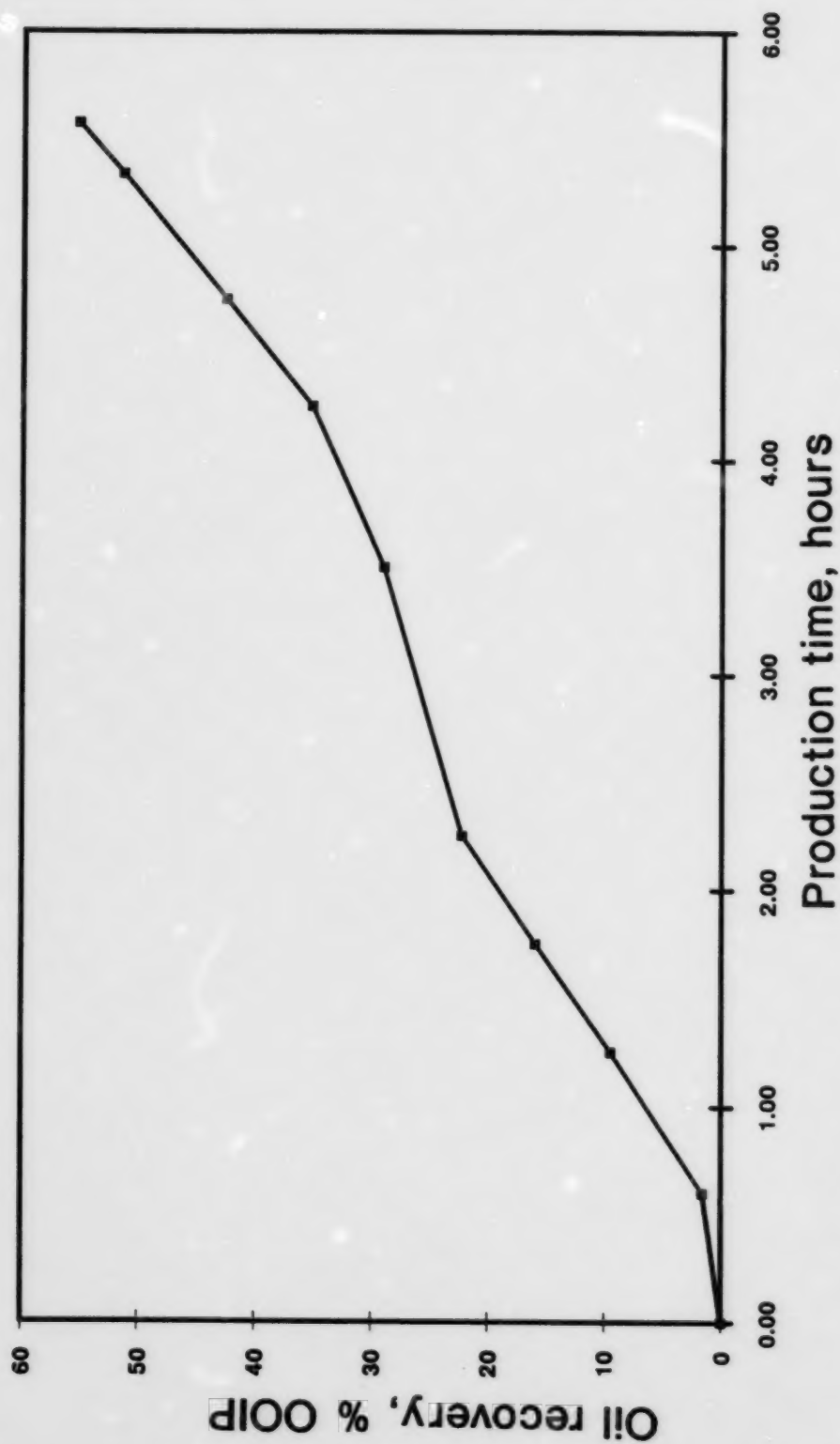


Figure 13: Oil recovery during waterflood of micromodel D2B.

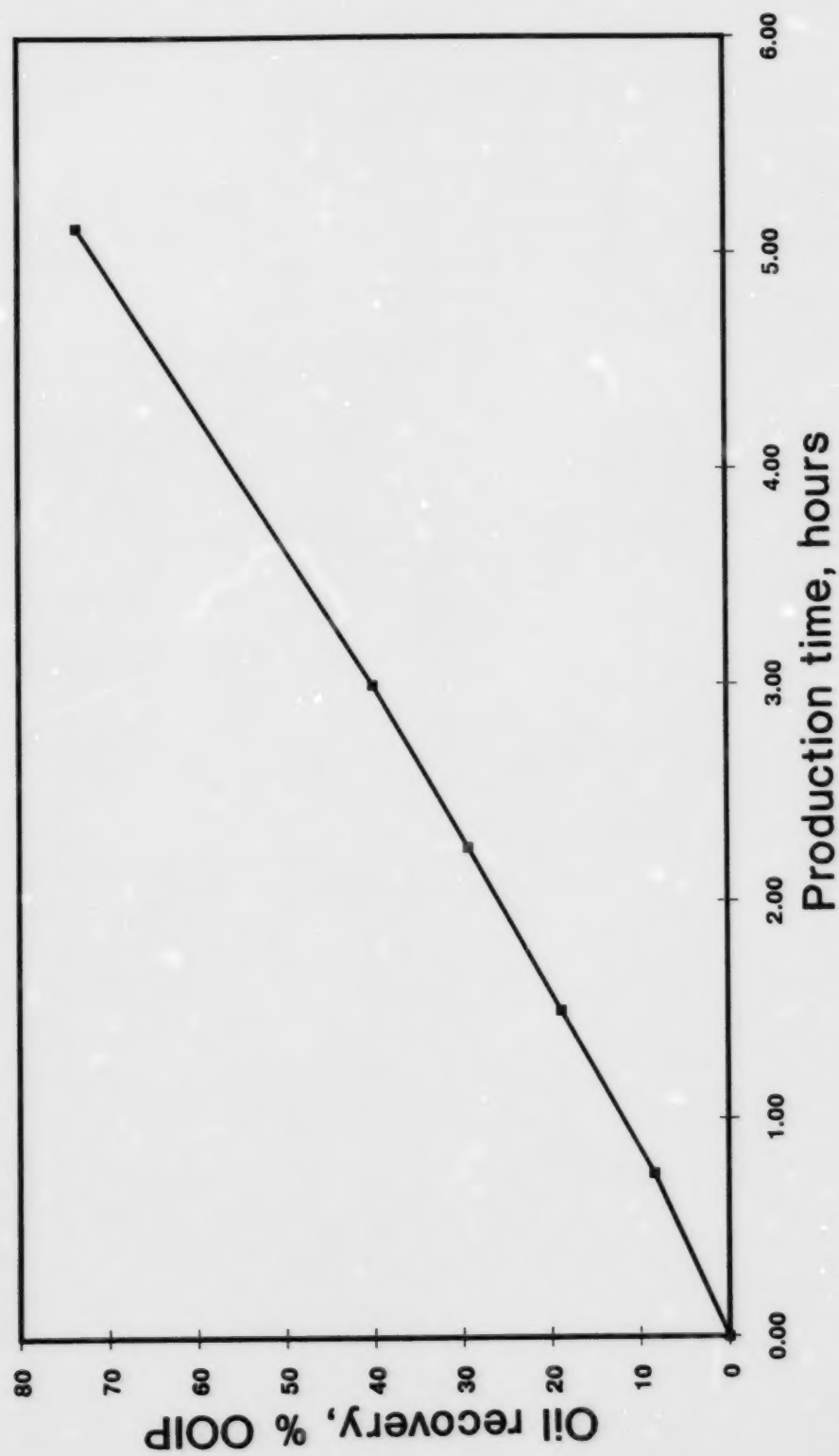


Figure 14: Oil recovery during waterflood of micromodel D2C.

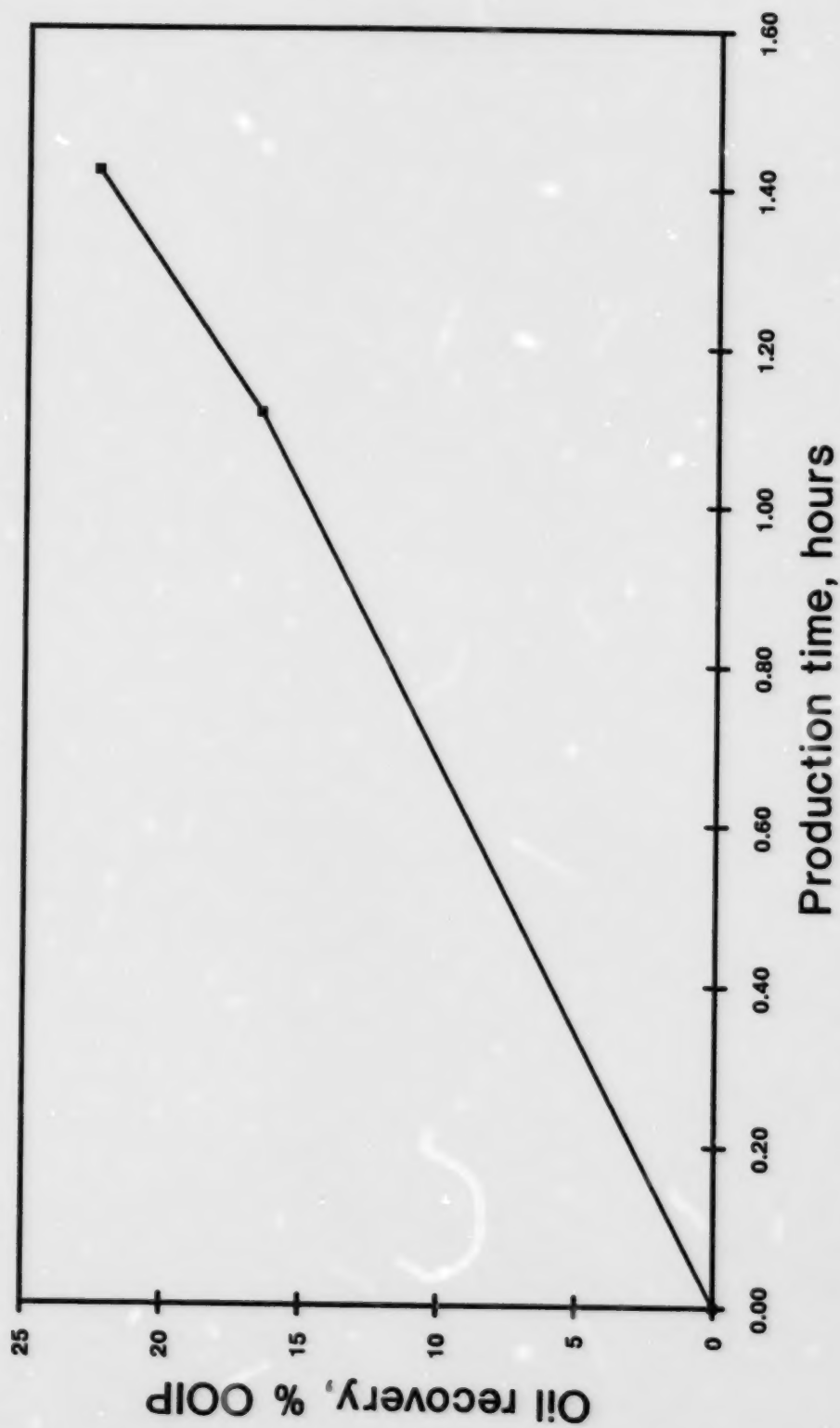


Figure 15: Oil recovery during waterflood of micromodel D1A.

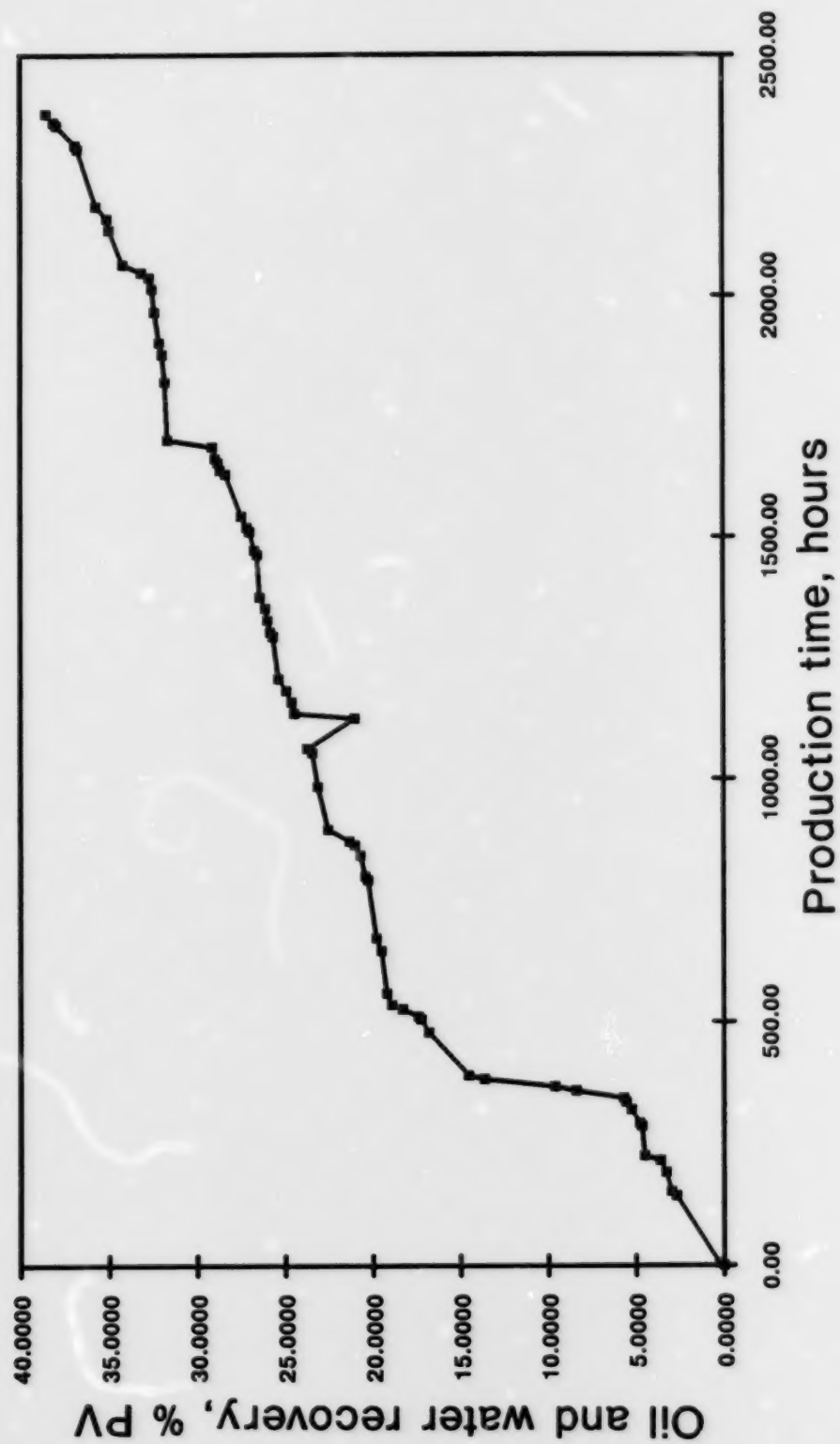


Figure 16: Liquid production curve for gas injection in micromodel D1A.

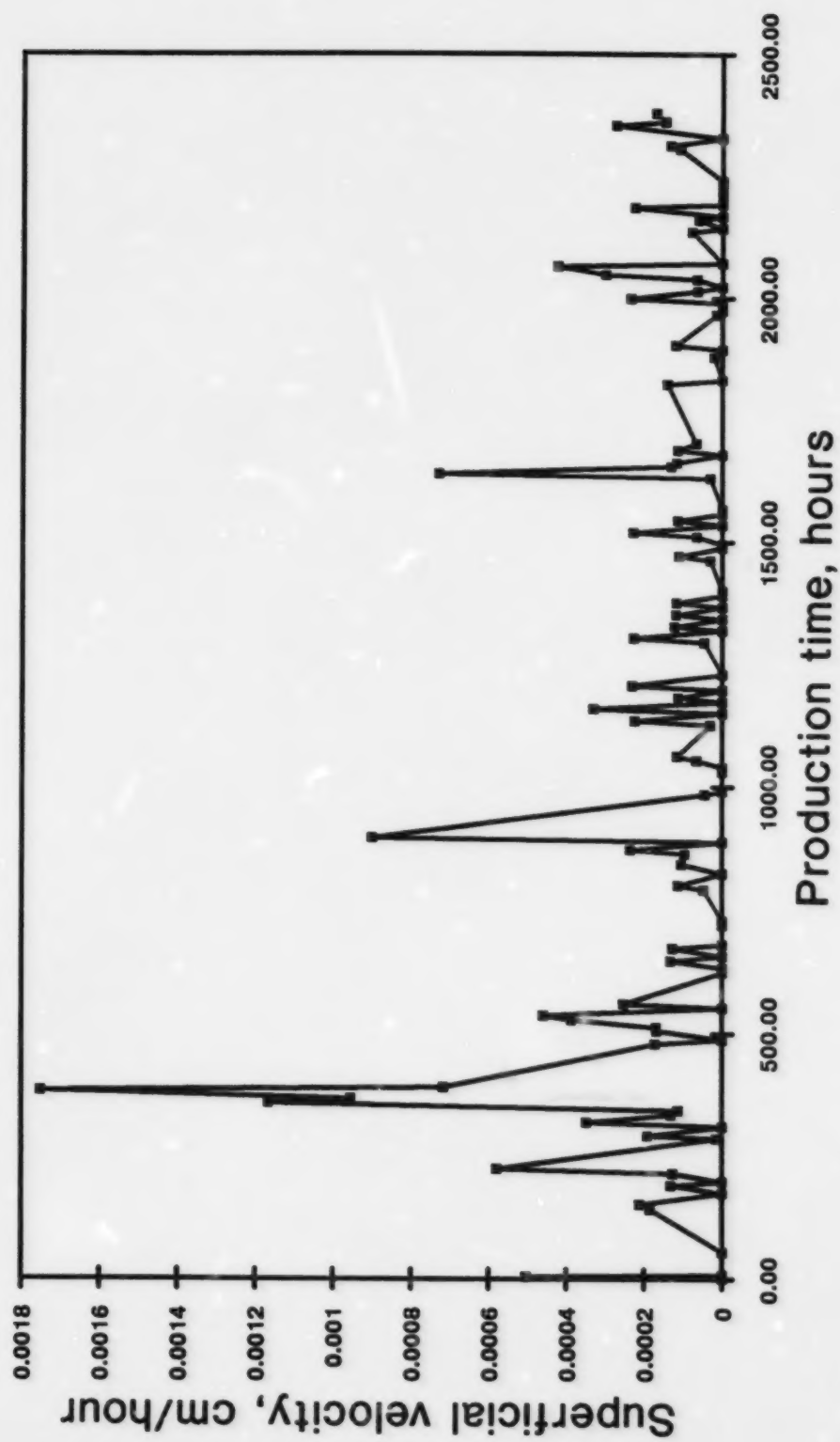


Figure 17: Superficial velocity during gas injection in micromodel D1.

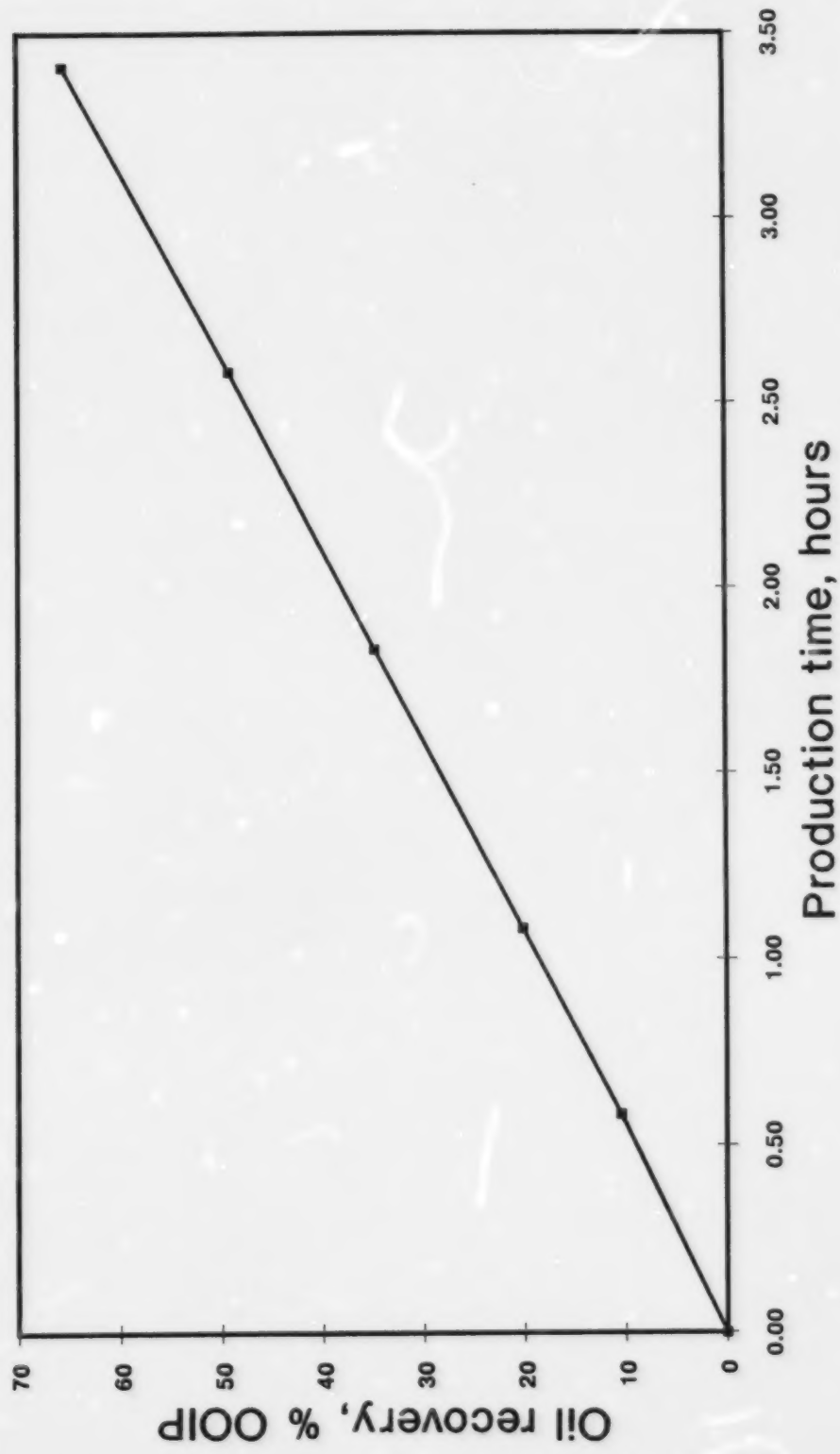


Figure 18: Oil recovery during waterflood of micromodel S1A (oil wet).

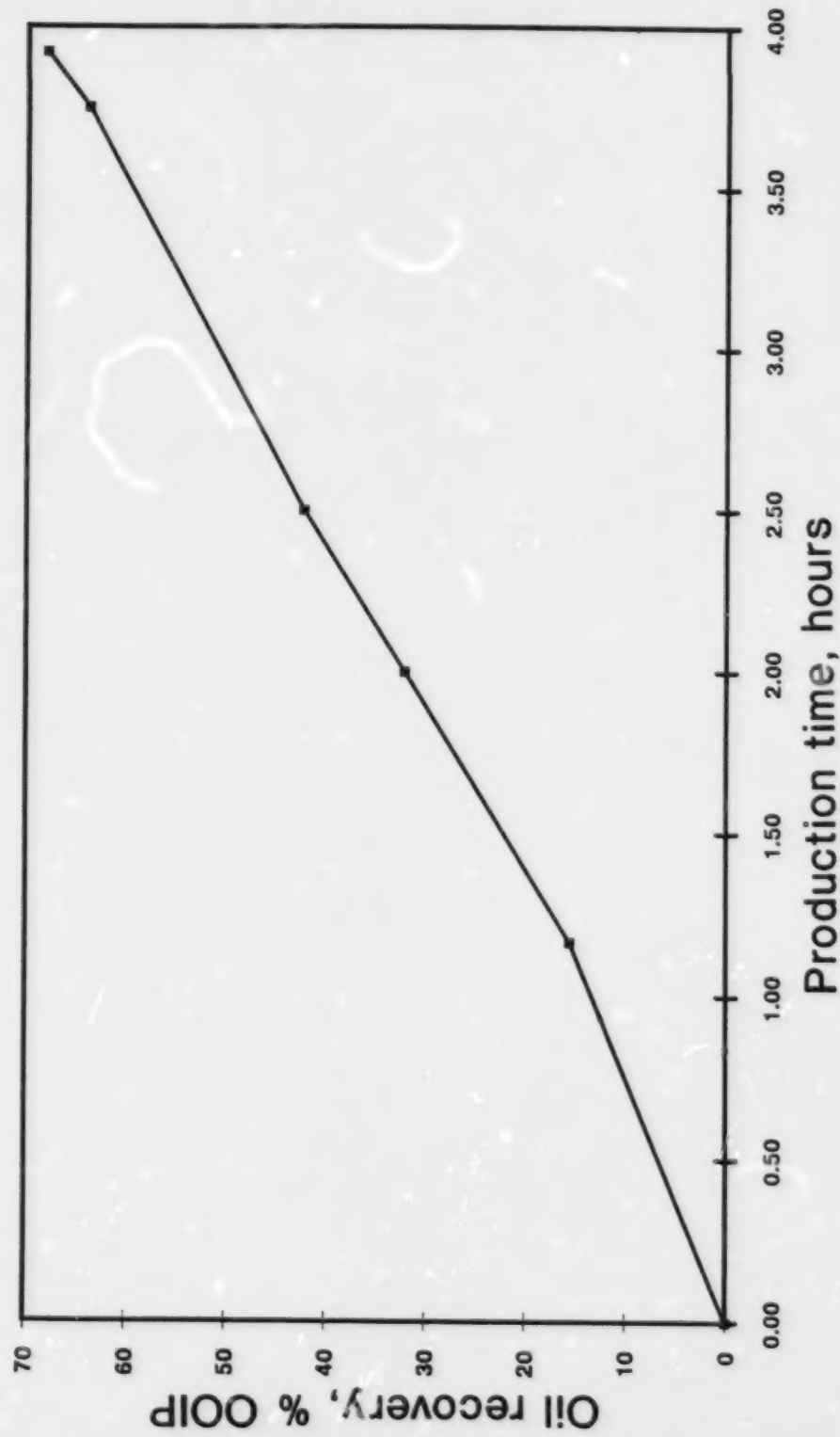


Figure 19: Oil recovery during waterflood of micromodel S1B (oil wet).

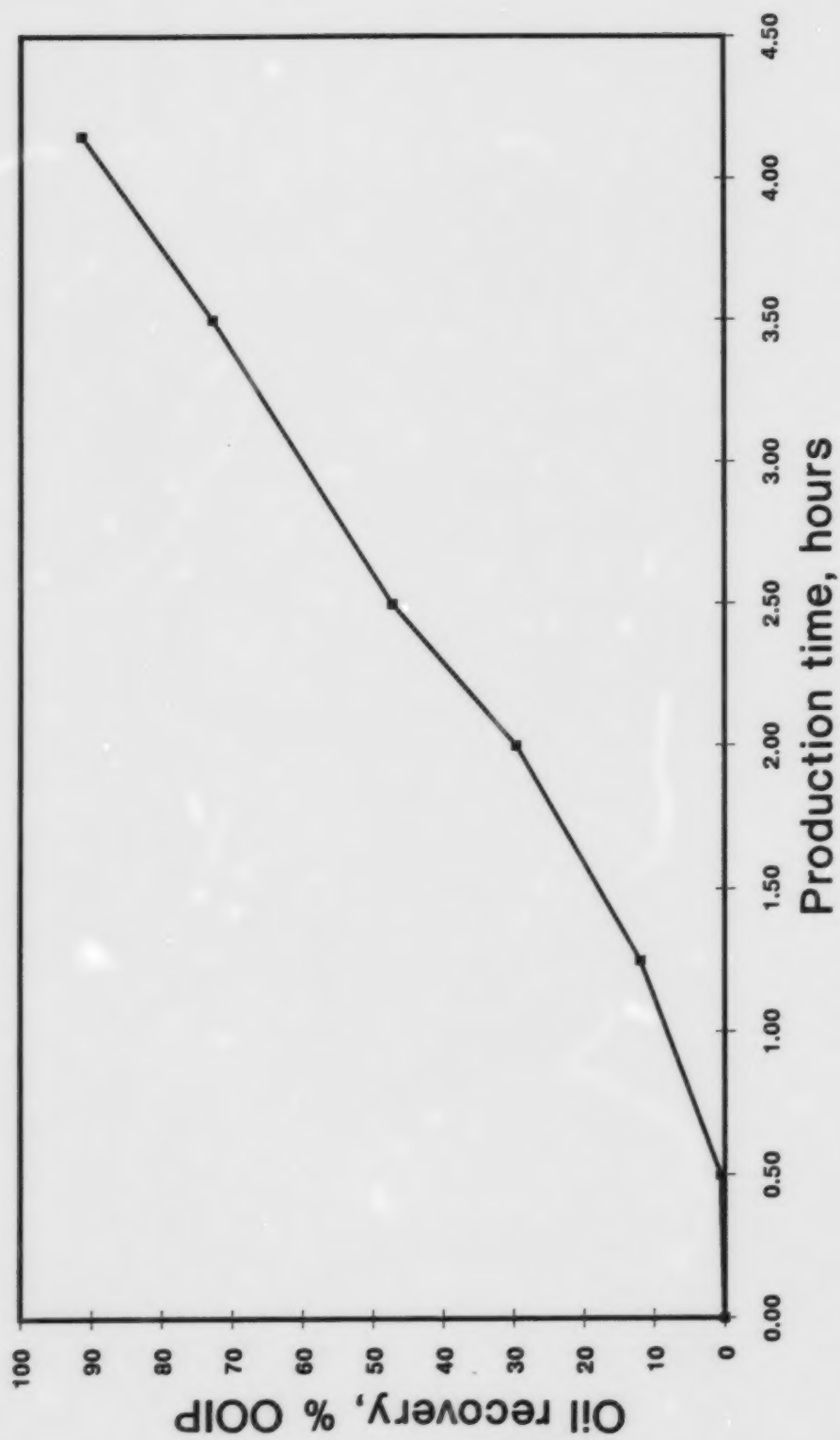
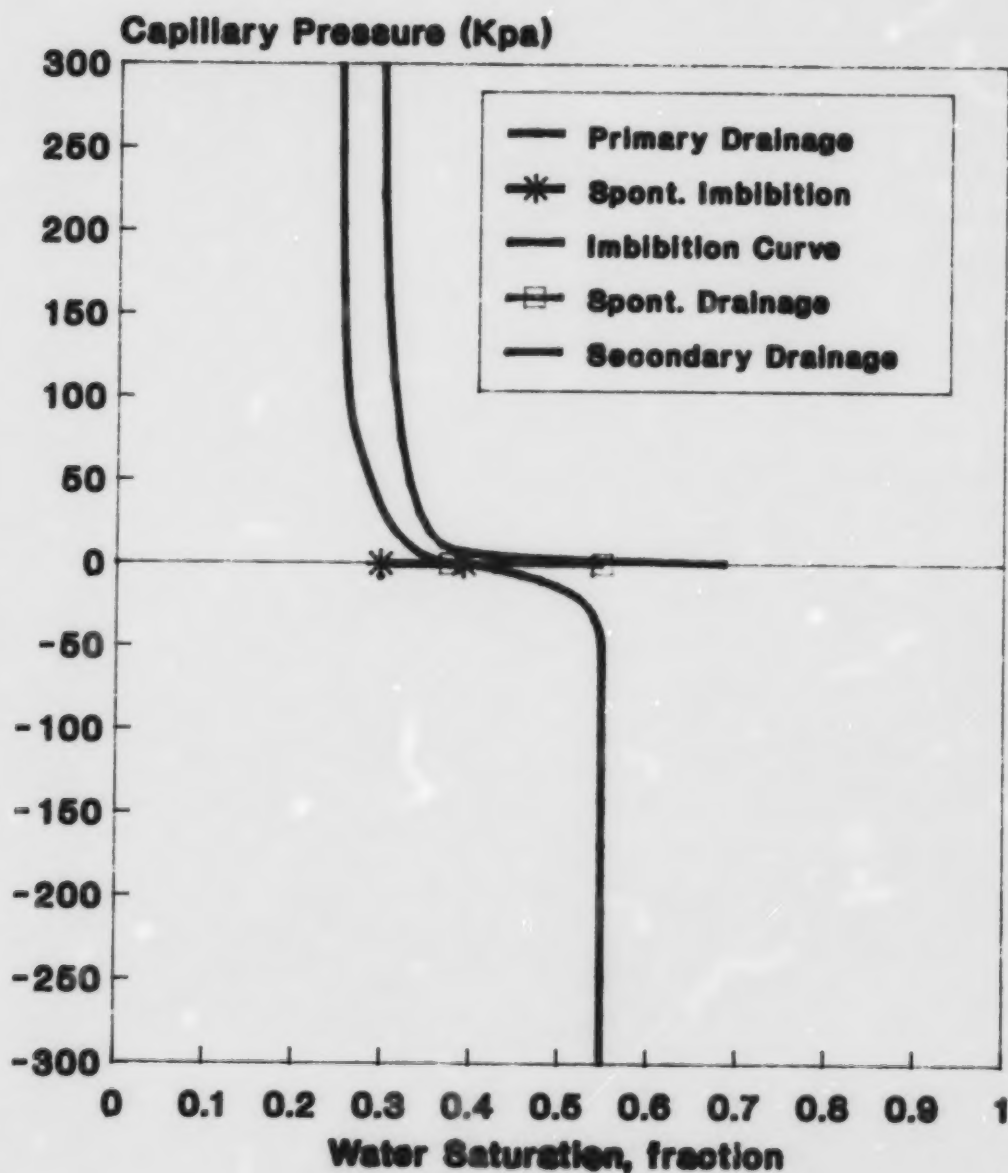


Figure 20: Oil recovery during waterflood of micromodel S1C (oil wet).

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #1A

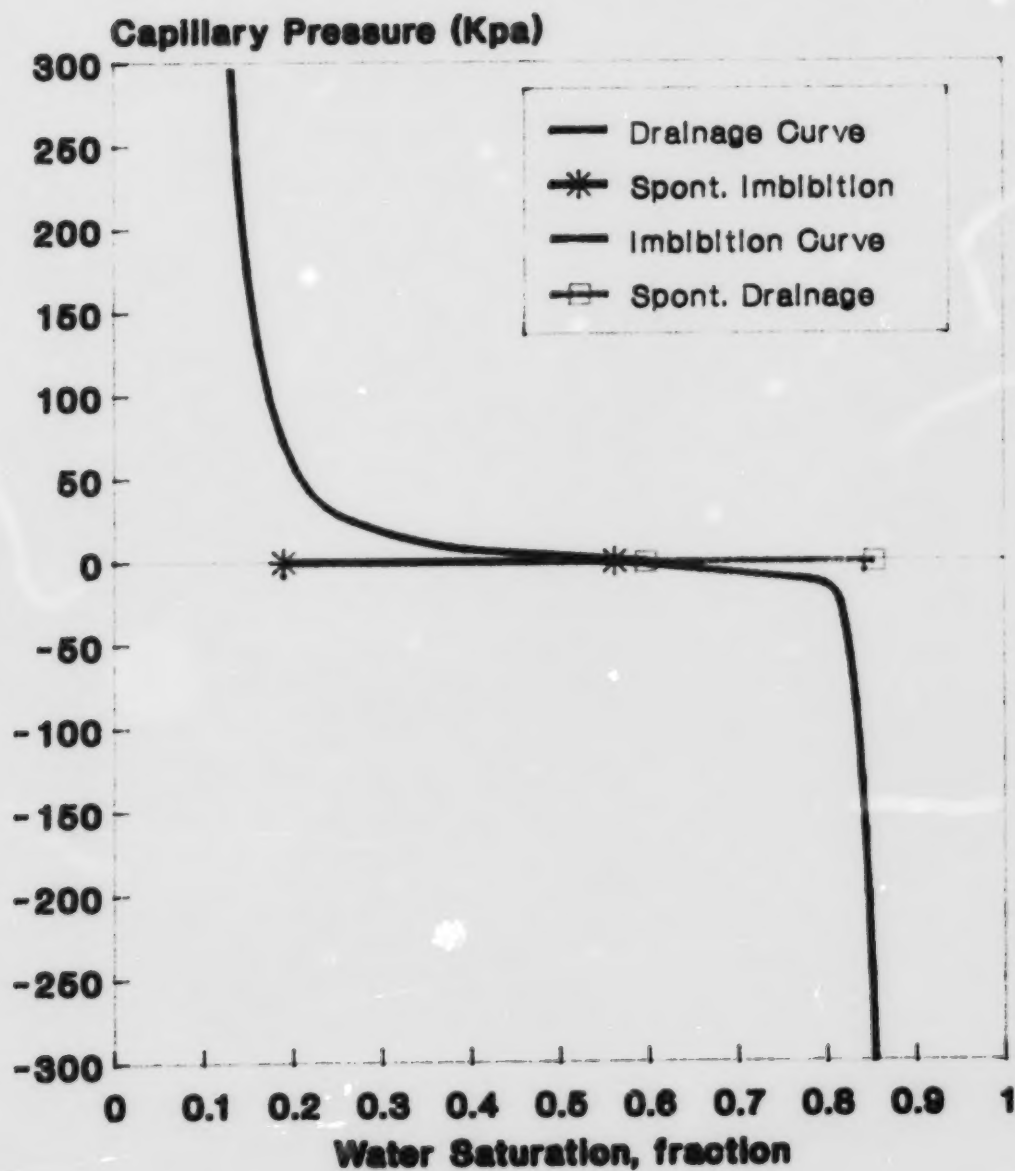


test performed at 87 C

Figure 21: Water/oil capillary pressure curve 9-28/1A.

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #2A

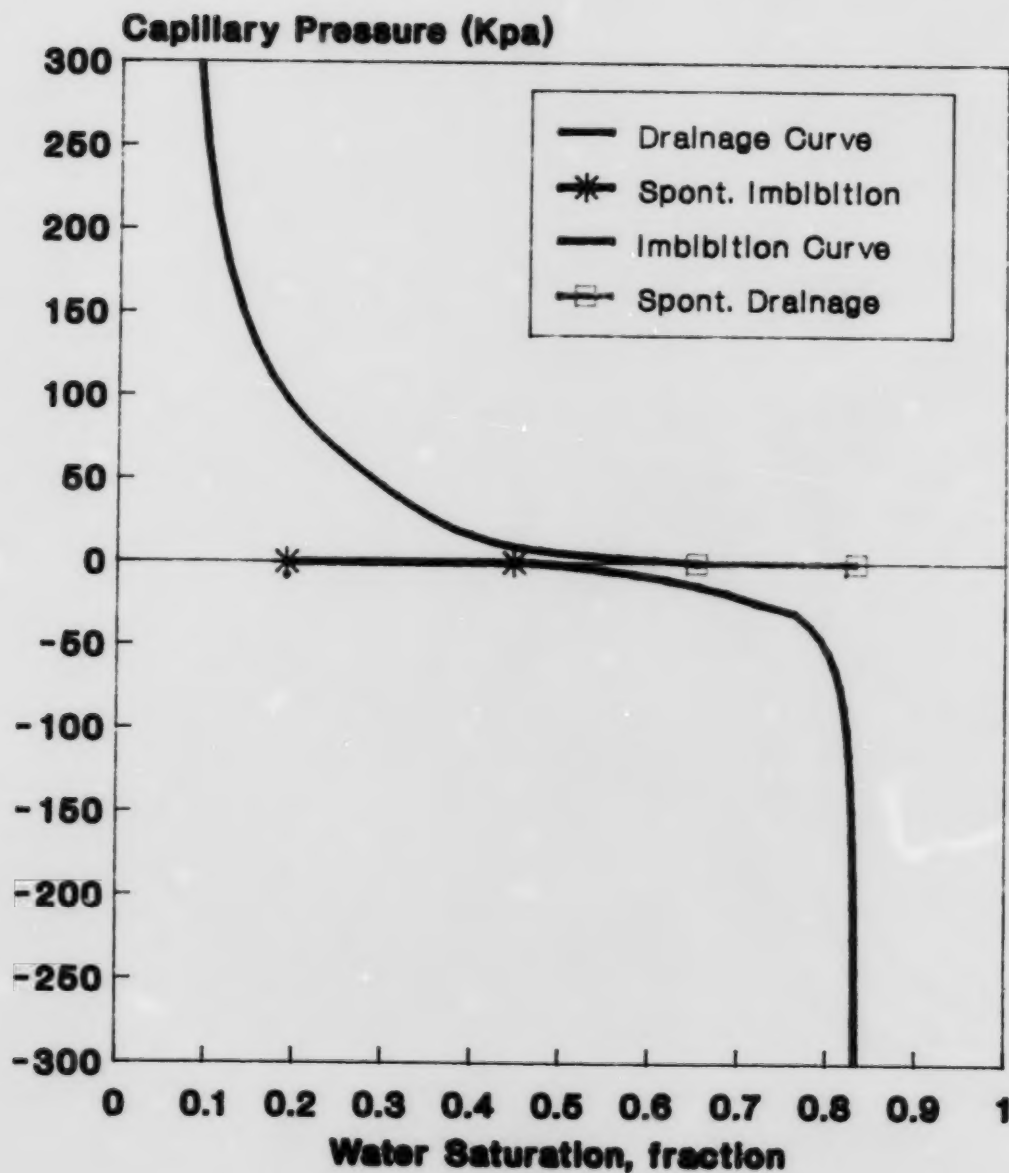


test performed at 87 C

Figure 22: Water/oil capillary pressure curve 9-28/2A.

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #3A

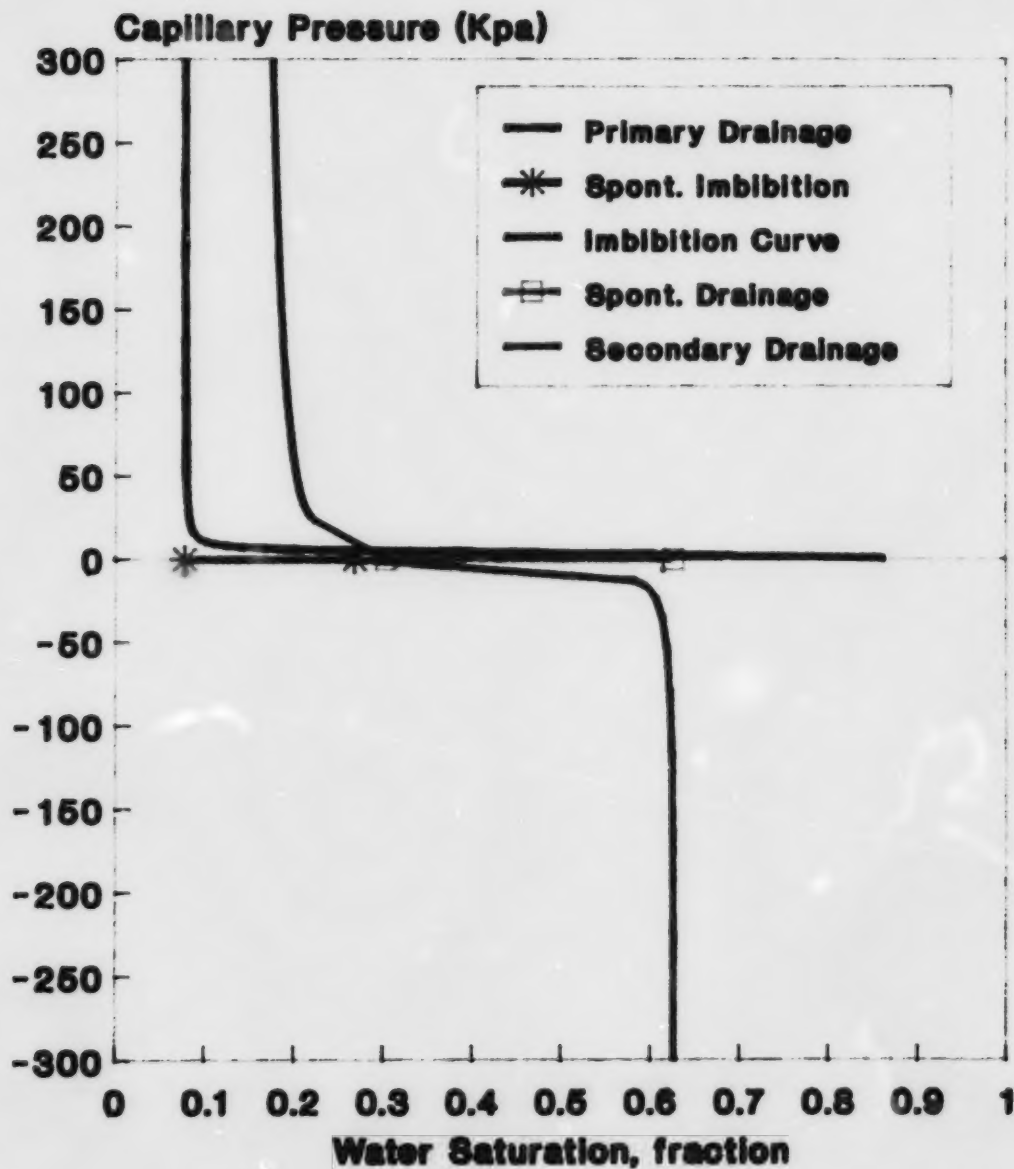


test performed at 87 C

Figure 23: Water/oil capillary pressure curve 9-28/3A.

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #8A

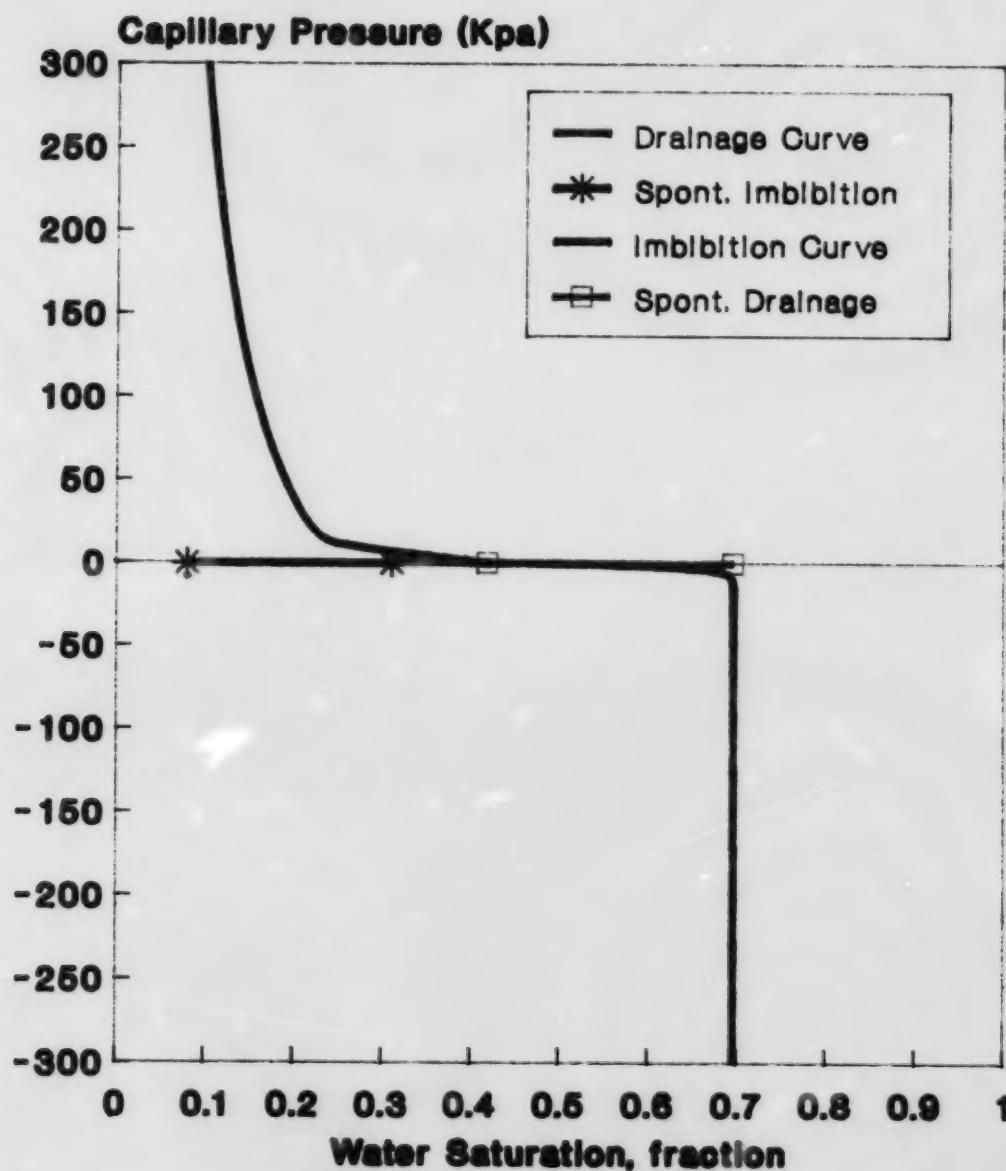


test performed at 87 C

Figure 24: Water/oil capillary pressure curve 9-28/8A.

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #10A

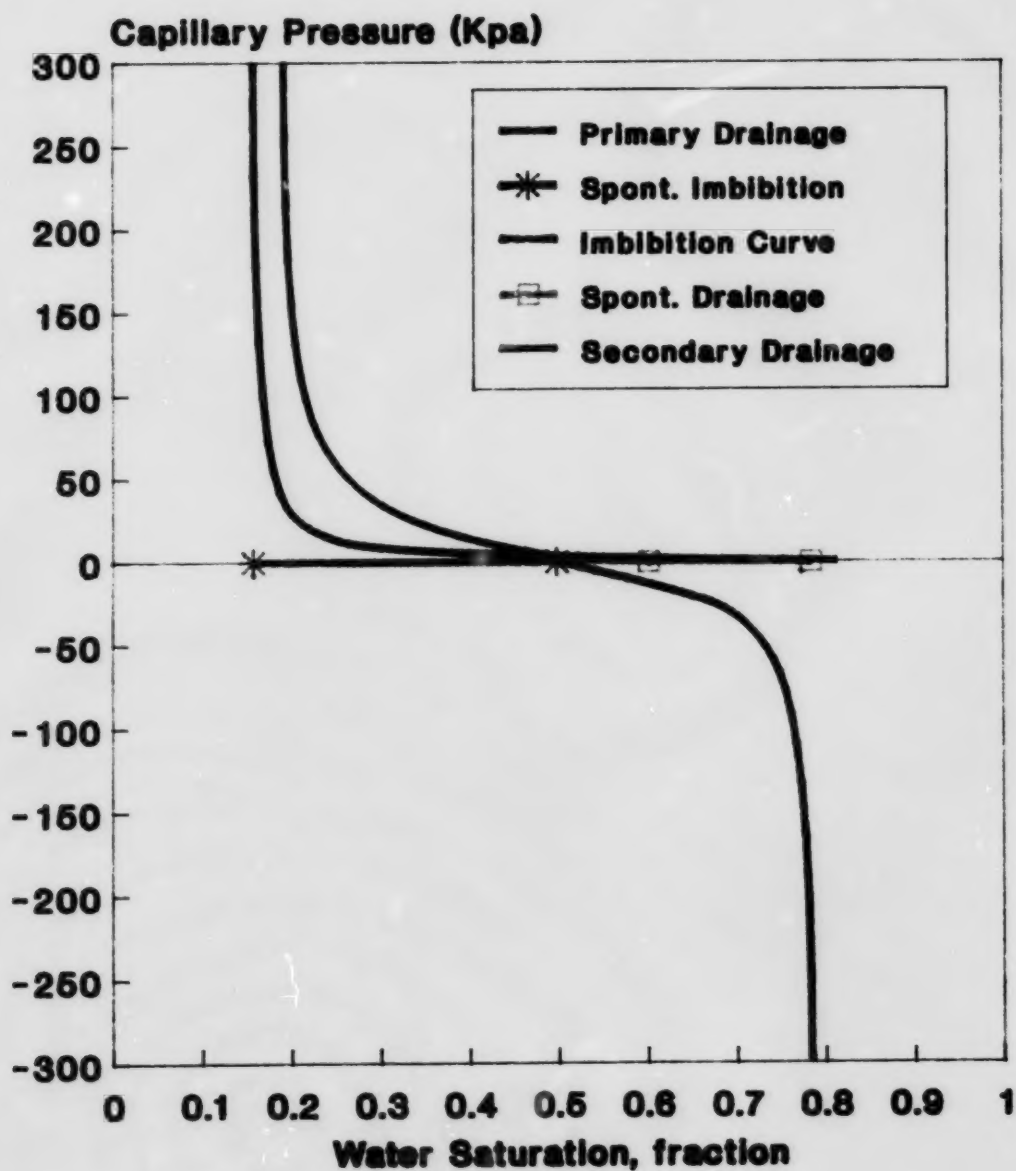


test performed at 87 C

Figure 25: Water/oil capillary pressure curve 9-28/10A.

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #11A

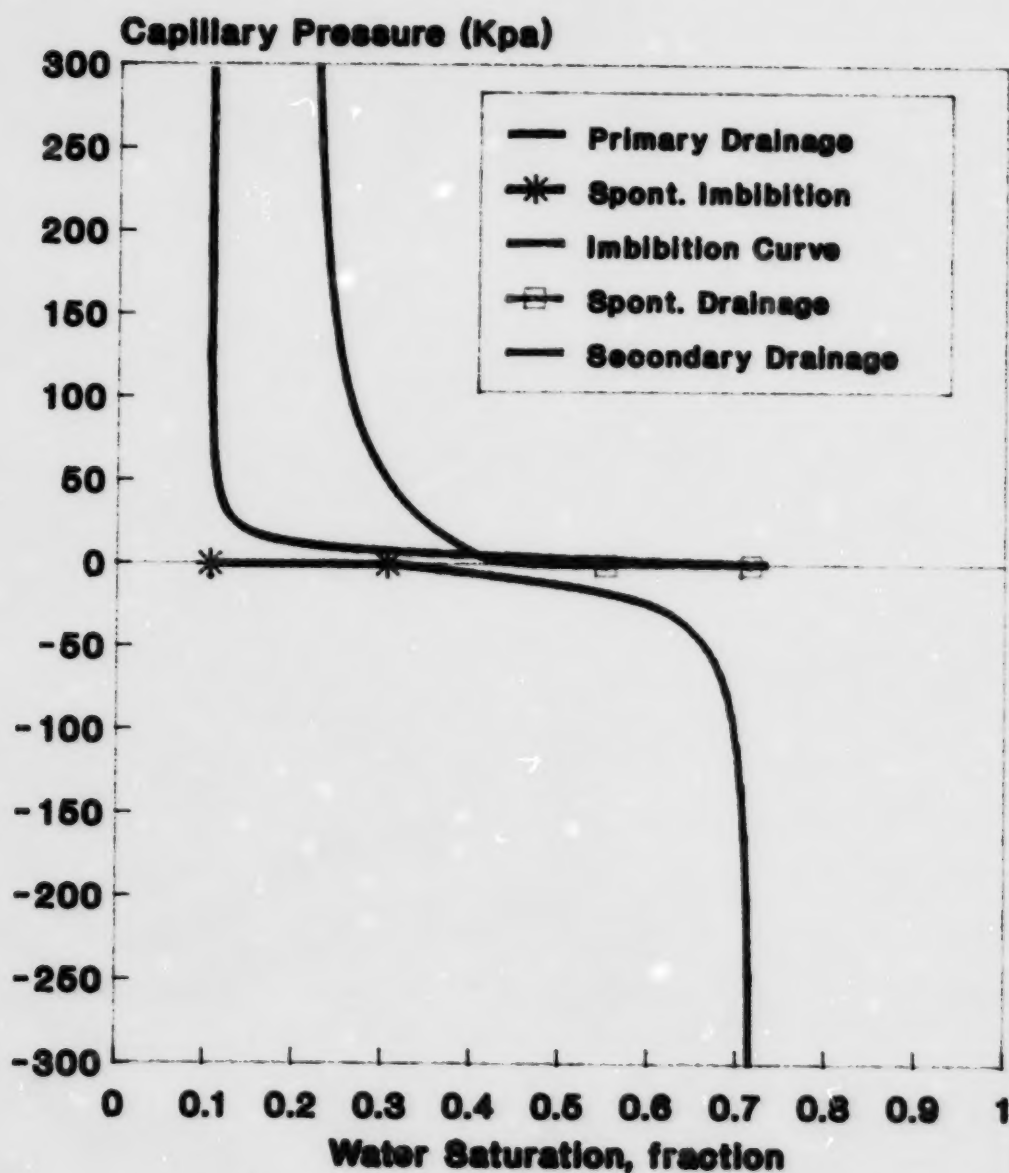


test performed at 87 C

Figure 26: Water/oil capillary pressure curve 9-28/11A.

Capillary Pressure Curves

Rainbow Lk Keg River / 9-28: Sample #14A

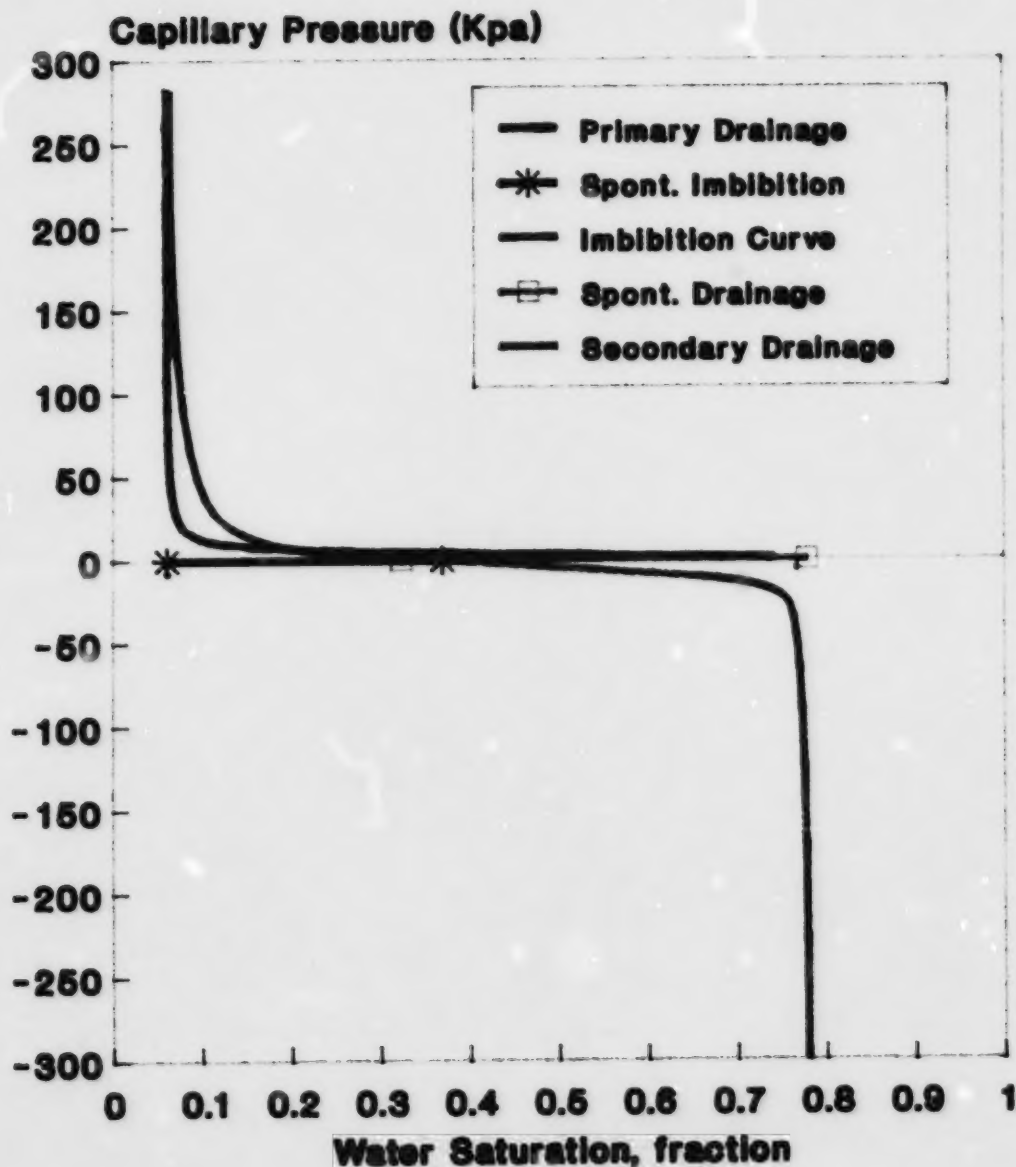


test performed at 87 C

Figure 27: Water/oil capillary pressure curve 9-28/14A.

Capillary Pressure Curves

Rainbow Lk Keg River / 6-6: Sample #1A

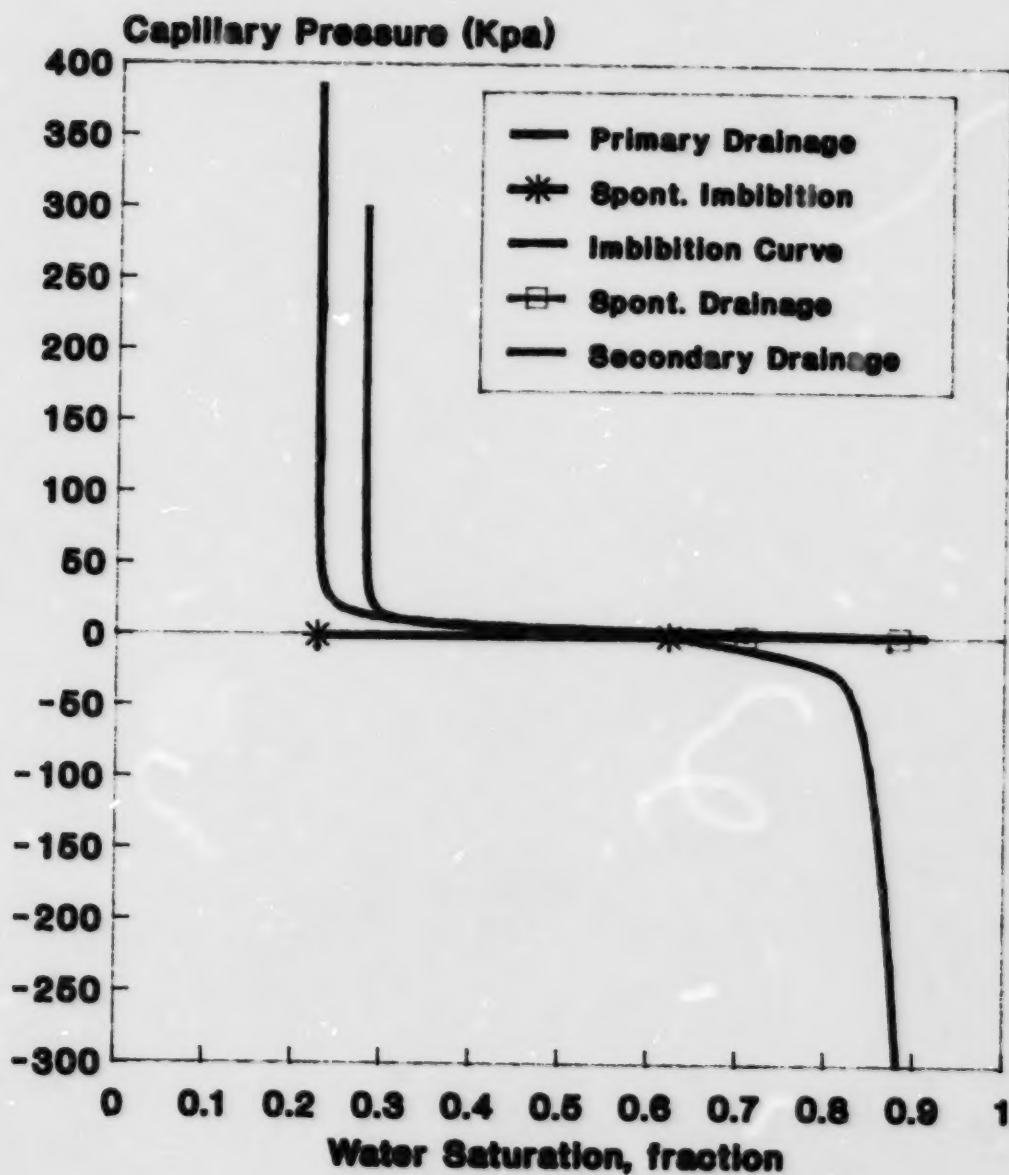


test performed at 87 C

Figure 28: Water/oil capillary pressure curve 6-6/1A.

Capillary Pressure Curves

Rainbow Lk Keg River / 6-6: Sample #2A

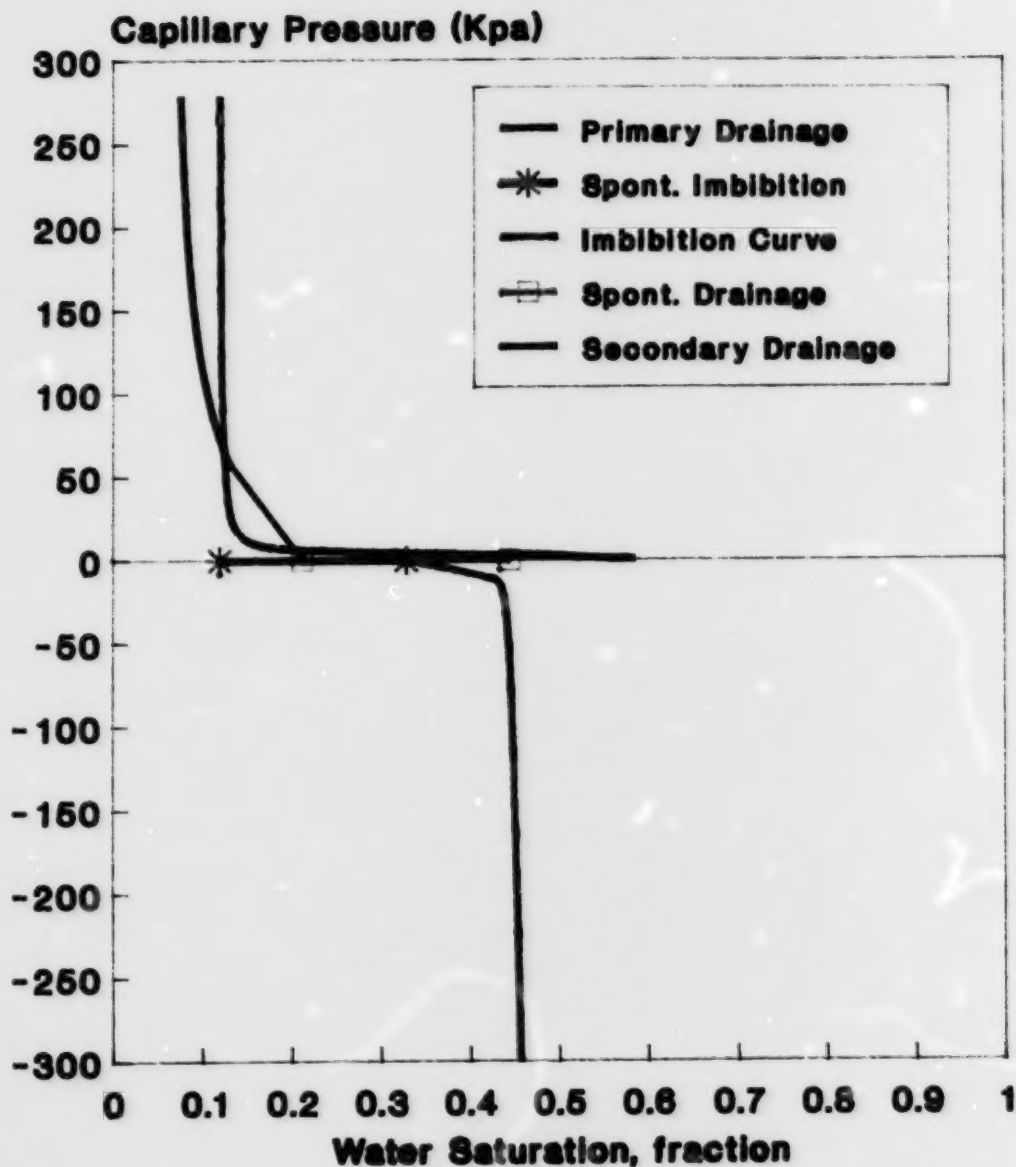


test performed at 87 C

Figure 29: Water/oil capillary pressure curve 6-6/2A.

Capillary Pressure Curves

Rainbow Lk Keg River / 6-6: Sample #4A

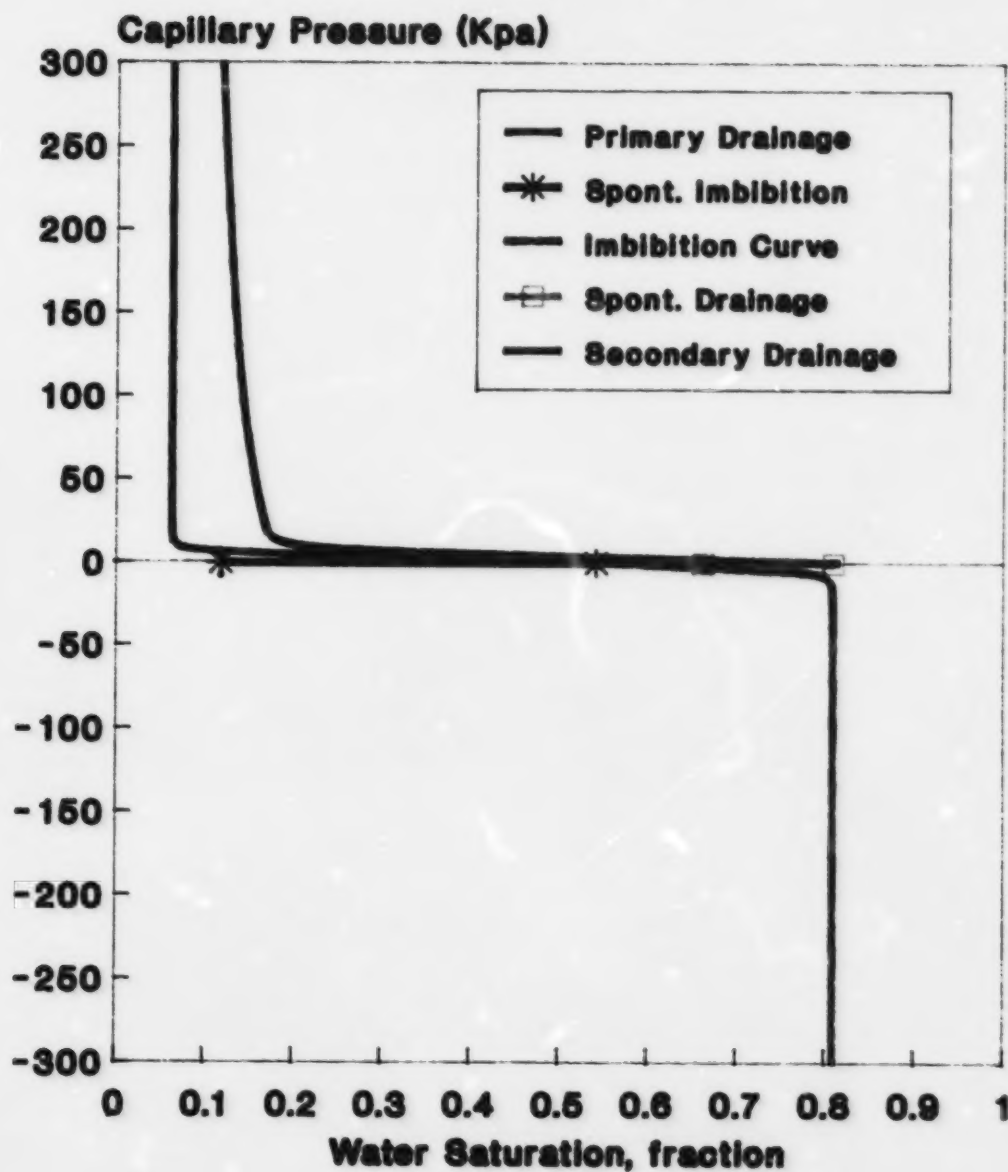


test performed at 87 C

Figure 30: Water/oil capillary pressure curve 6-6/4A.

Capillary Pressure Curves

Rainbow Lk Keg River / 6-6: Sample #5A

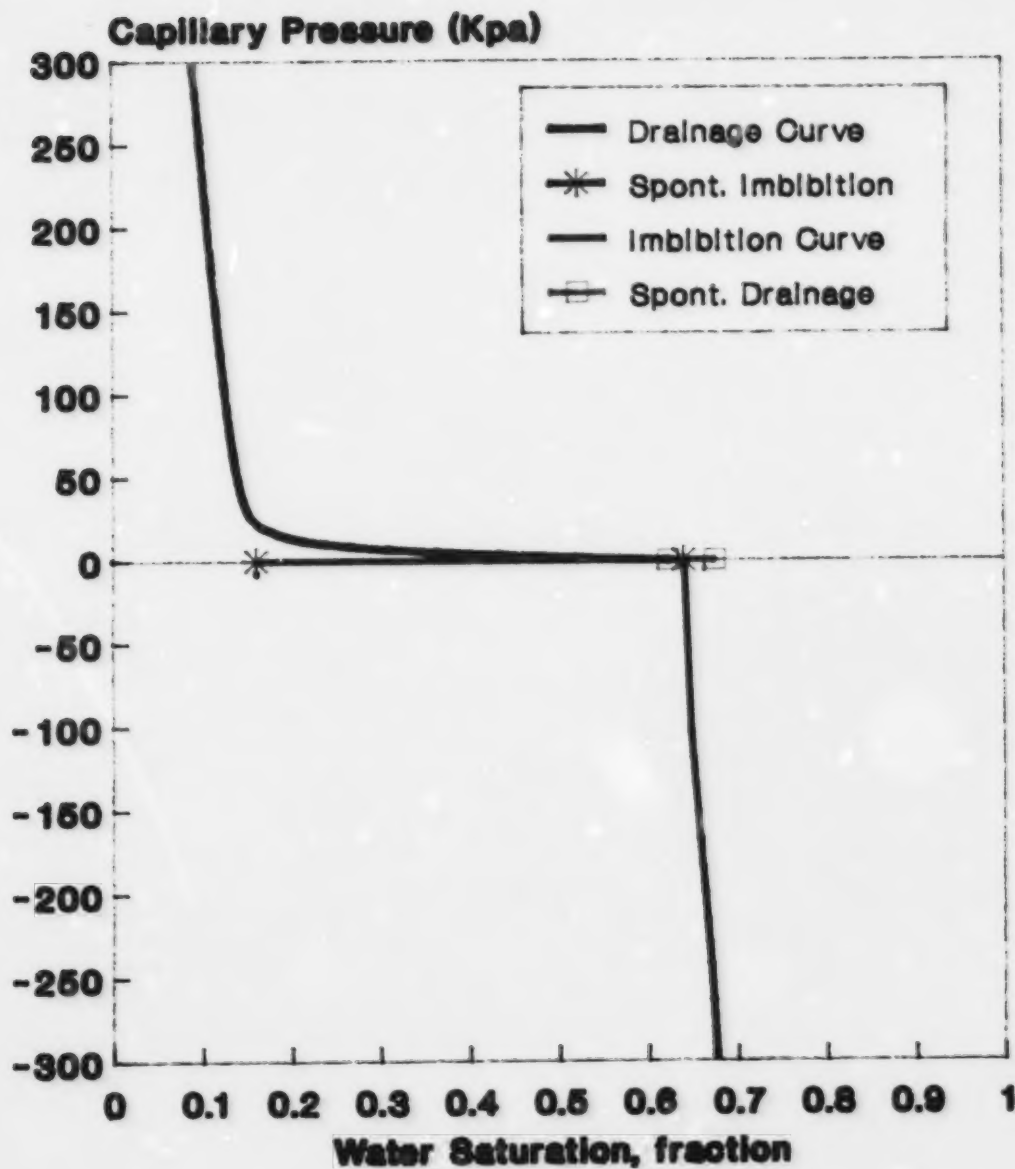


test performed at 87 C

Figure 31: Water/oil capillary pressure curve 6-6/5A.

Capillary Pressure Curves

Berea Sandstone Test Sample #01

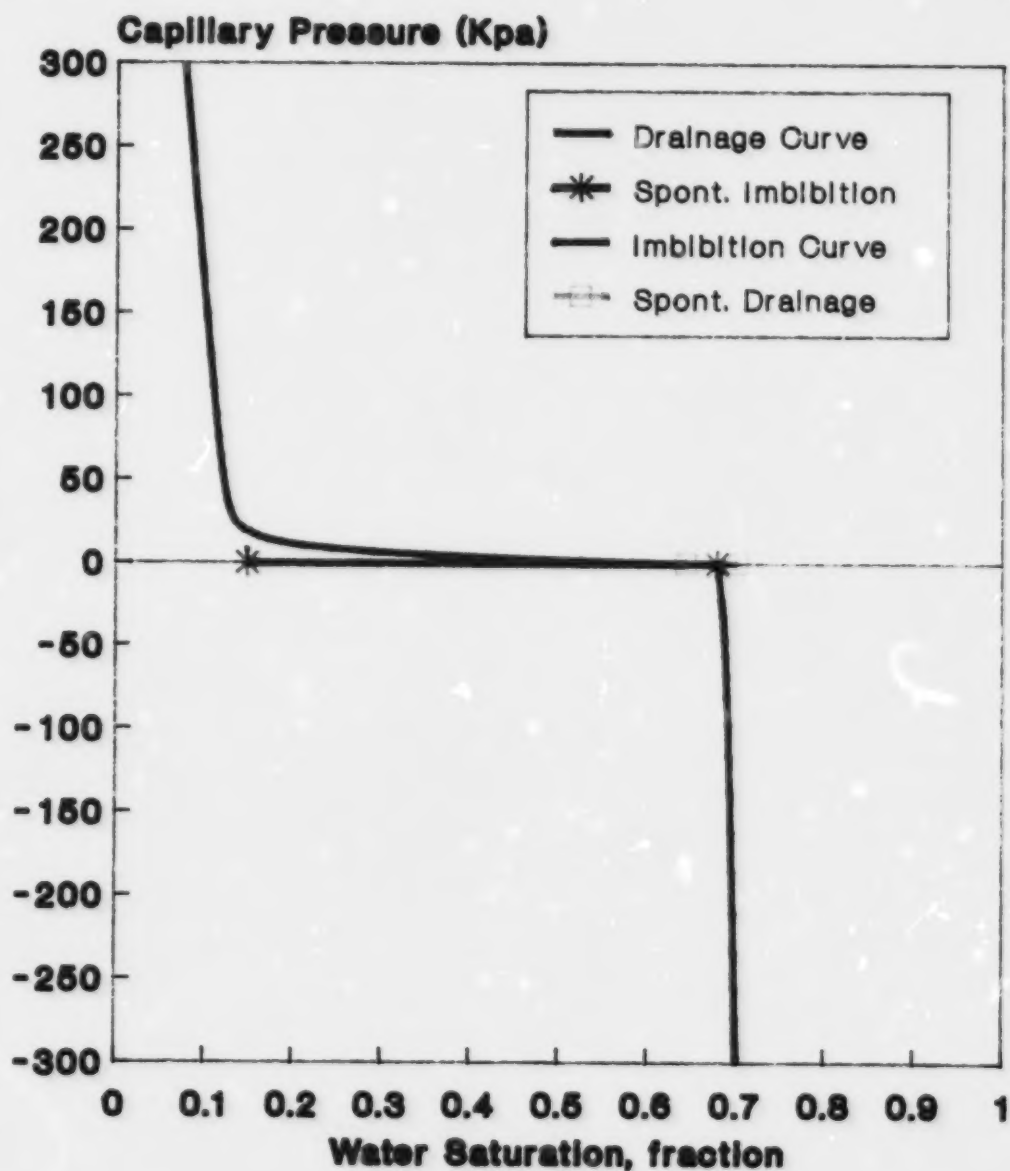


test performed at 87 C

Figure 32: Water/oil capillary pressure curve Berea 01.

Capillary Pressure Curves

Berea Sandstone Test Sample #02

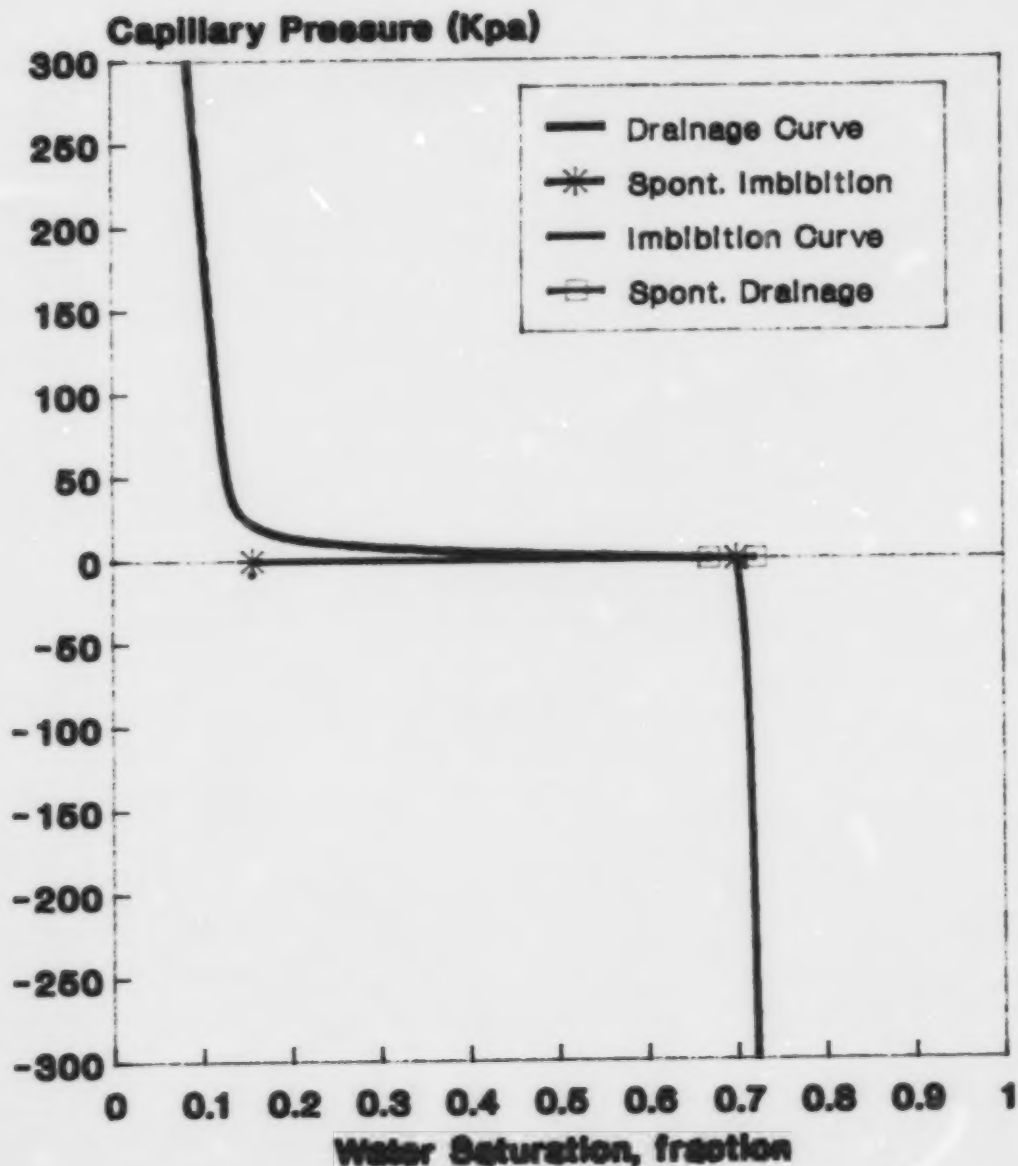


test performed at 87 C

Figure 33: Water/oil capillary pressure curve Berea 02.

Capillary Pressure Curves

Berea Sandstone Test Sample #03

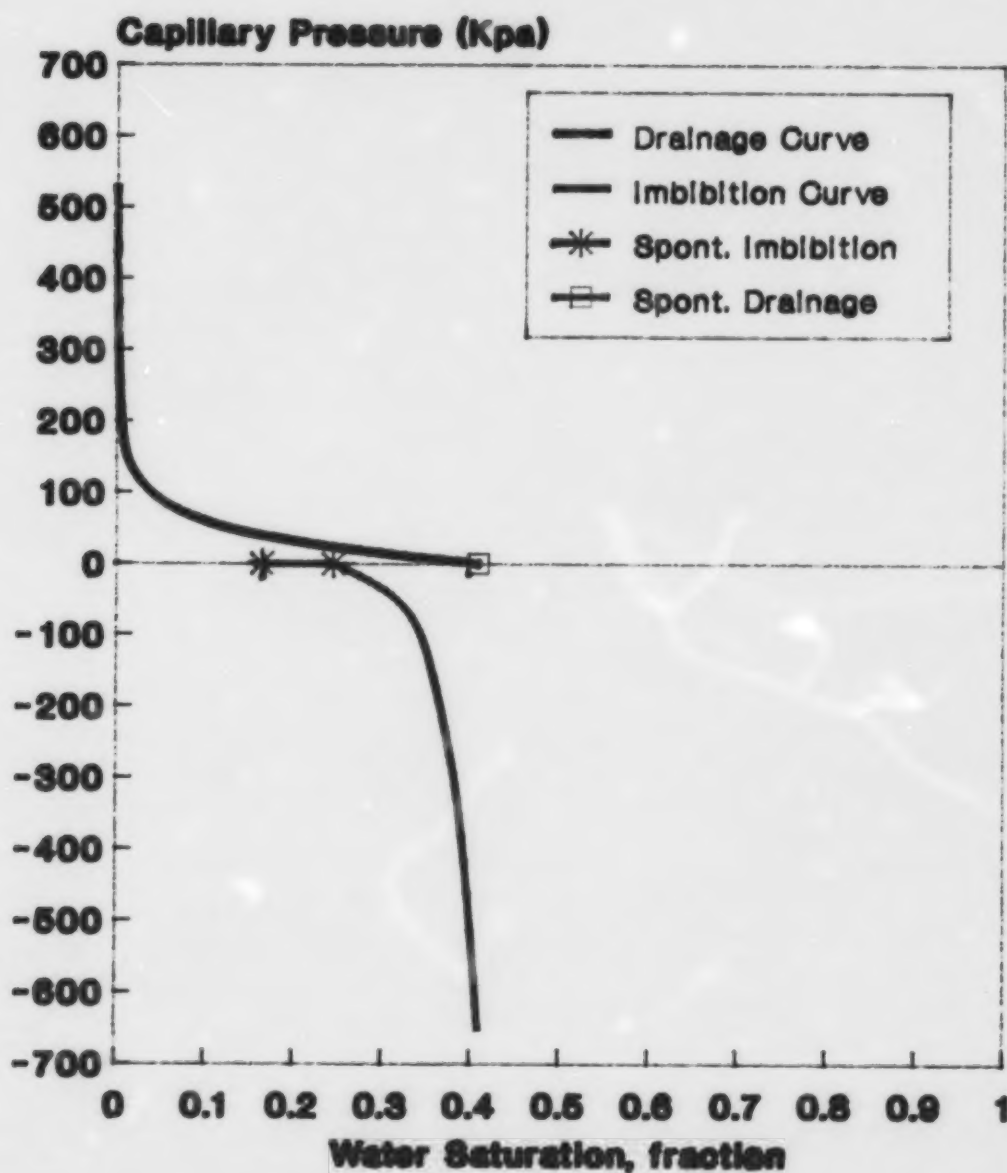


test performed at 87 C

Figure 34: Water/oil capillary pressure curve Berea 03.

Capillary Pressure Curves

Baker Dolomite Test Sample #01

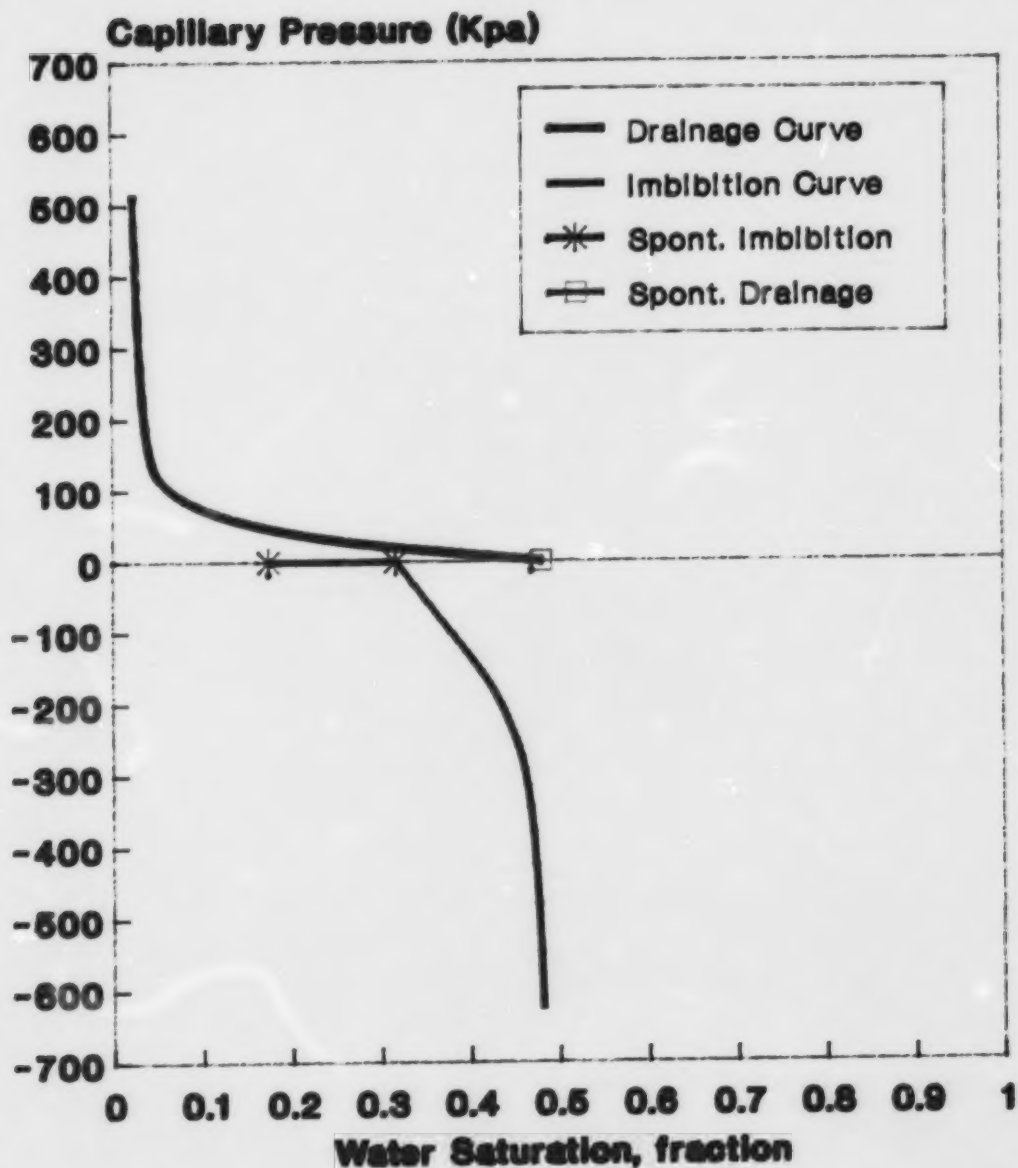


test performed at 25 C

Figure 35: Water/oil capillary pressure curve Baker 01.

Capillary Pressure Curves

Baker Dolomite Test Sample #02

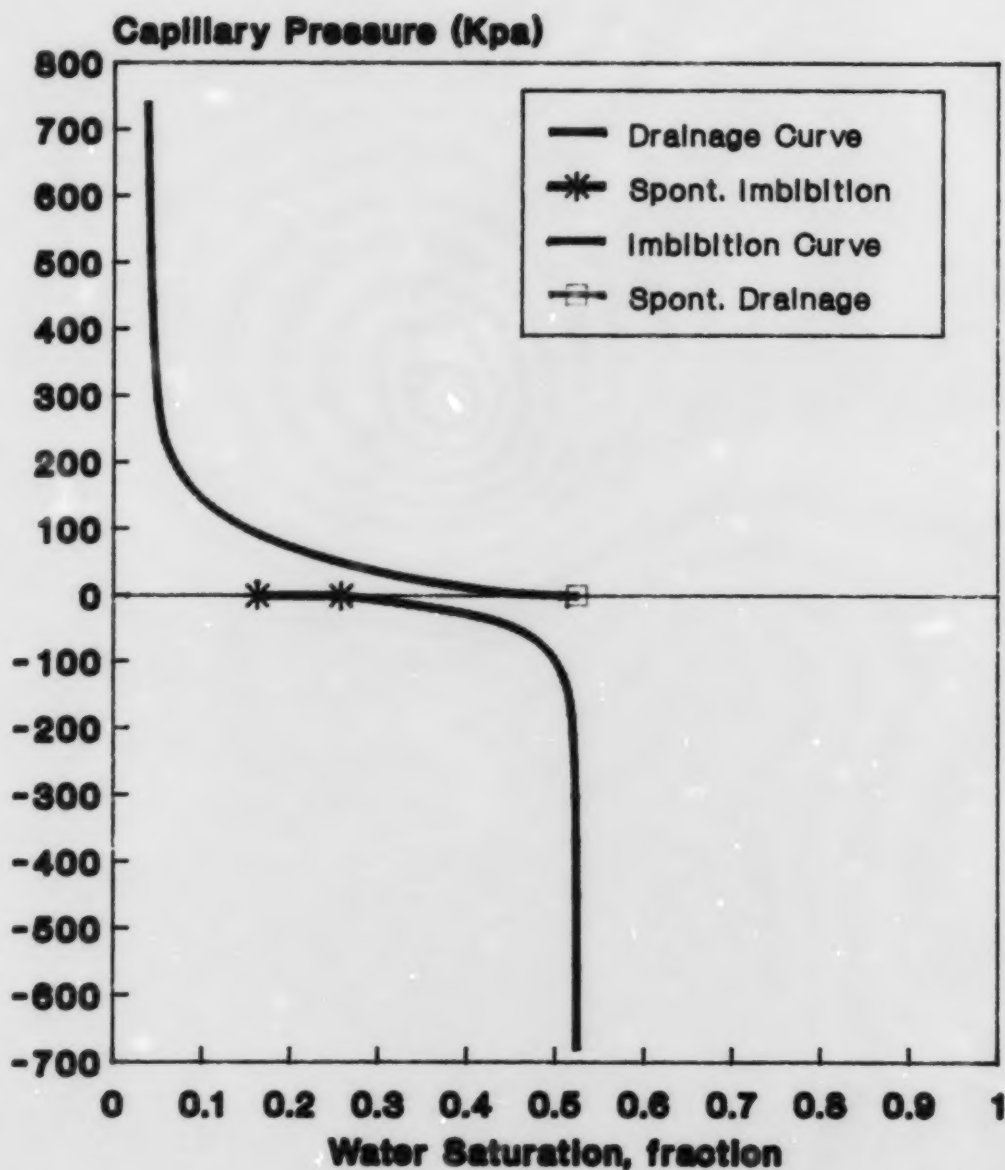


test performed at 25 C

Figure 36: Water/oil capillary pressure curve Baker 02.

Capillary Pressure Curves

Baker Dolomite Test Sample #03

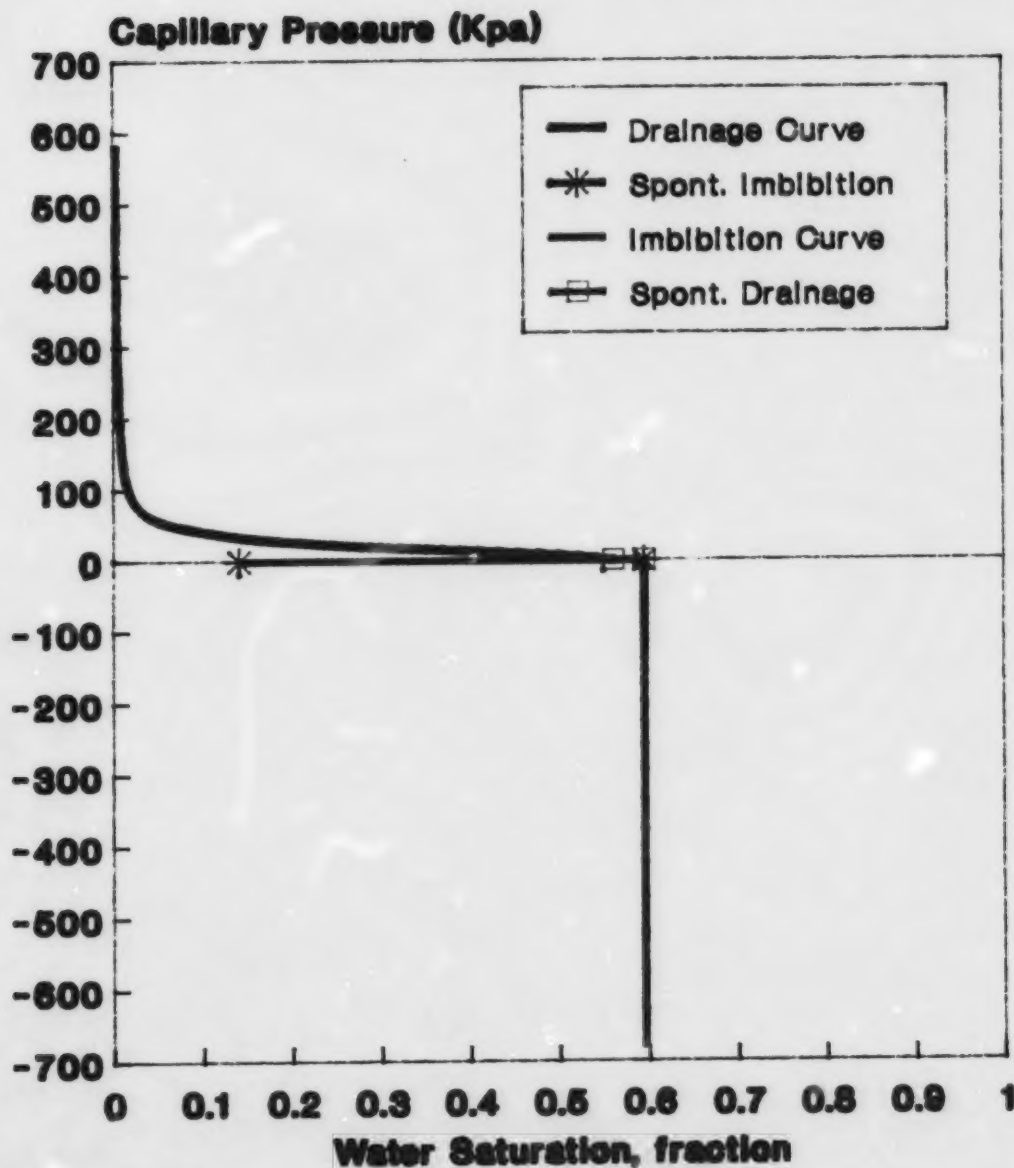


test performed at 25 C

Figure 37: Water/oil capillary pressure curve Baker 03.

Capillary Pressure Curves

Baker Dolomite Test Sample #04

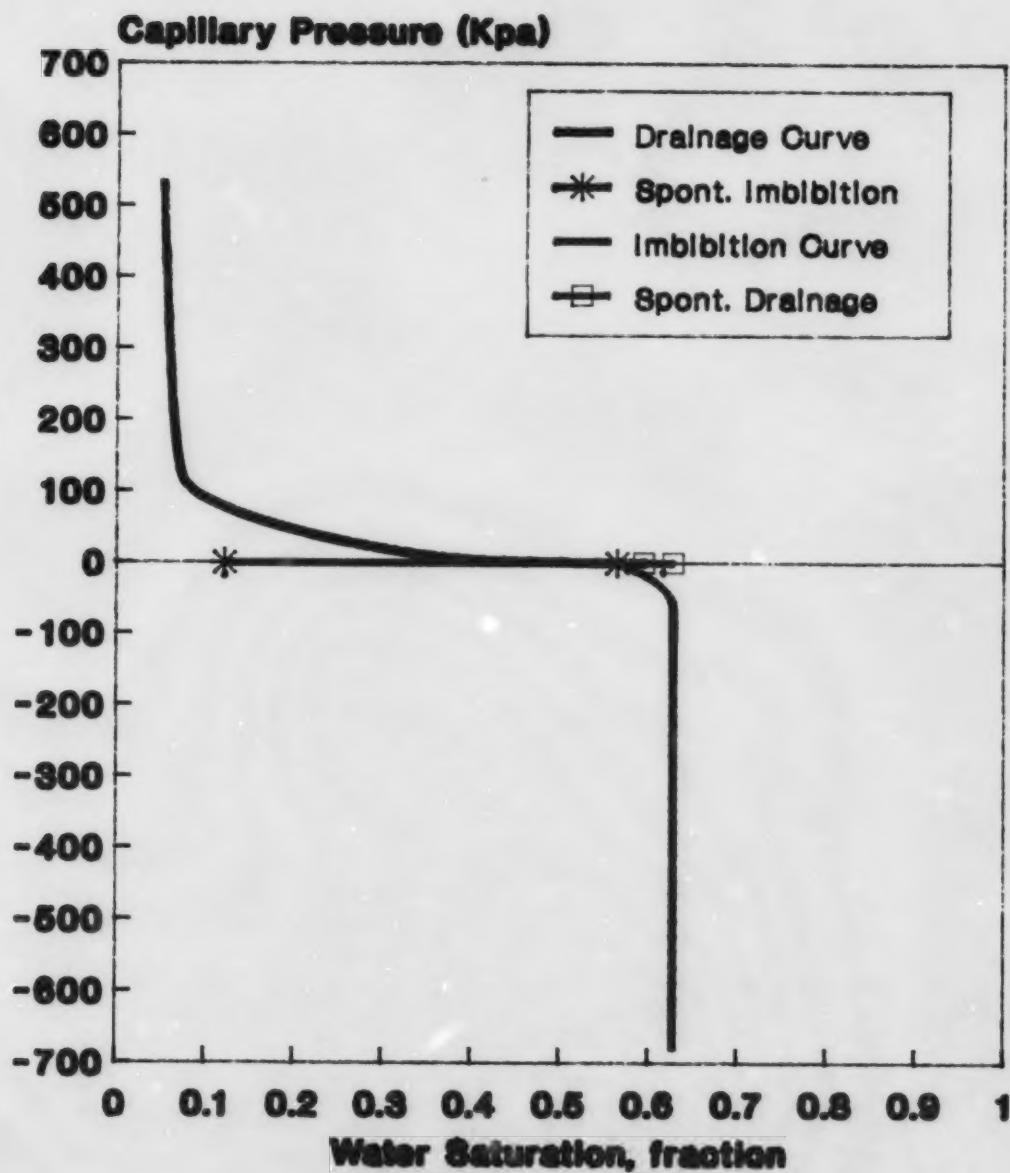


test performed at 87 C

Figure 38: Water/oil capillary pressure curve Baker 04.

Capillary Pressure Curves

Baker Dolomite Test Sample #05

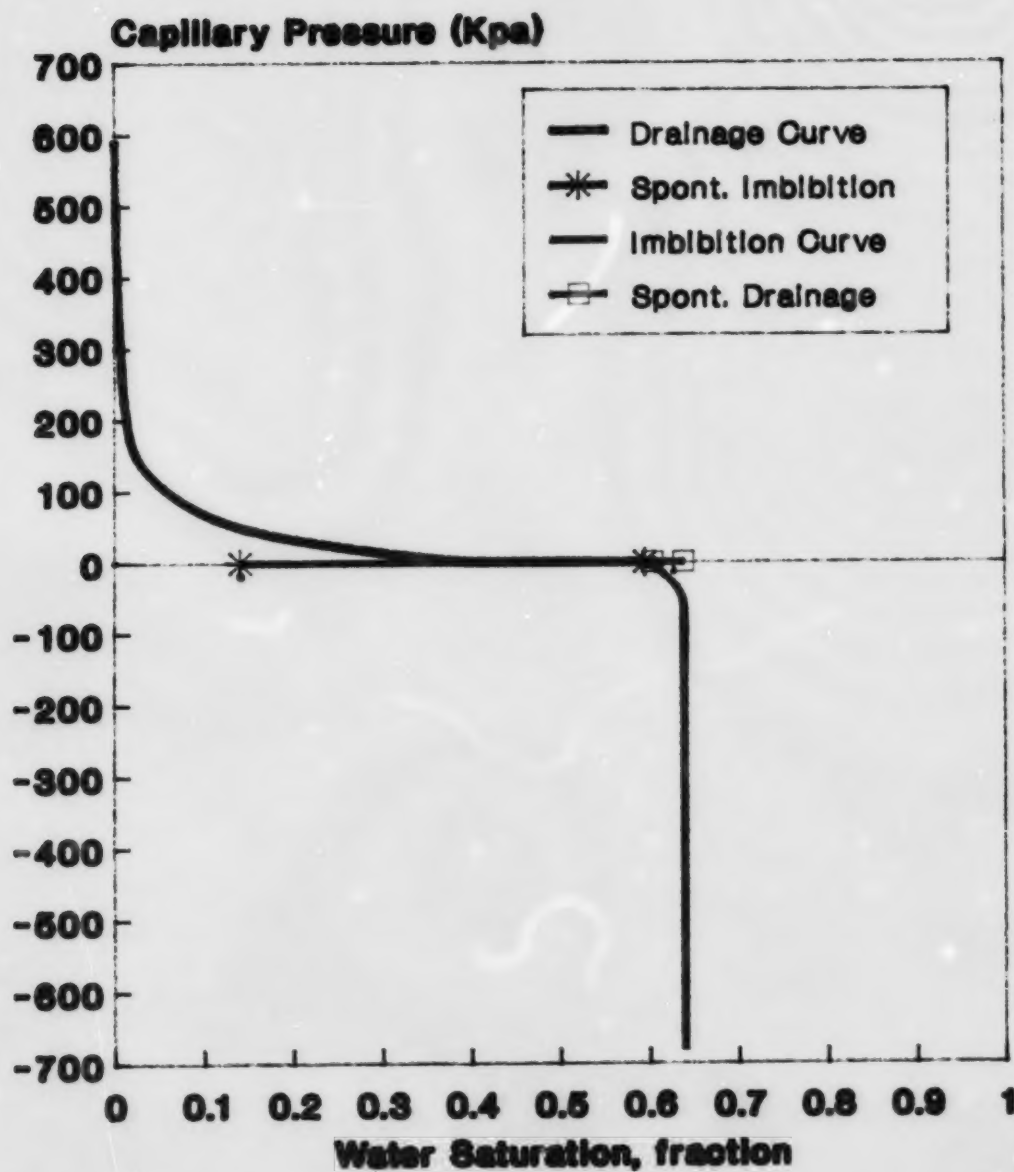


test performed at 87 C

Figure 39: Water/oil capillary pressure curve Baker 05.

Capillary Pressure Curves

Baker Dolomite Test Sample #06

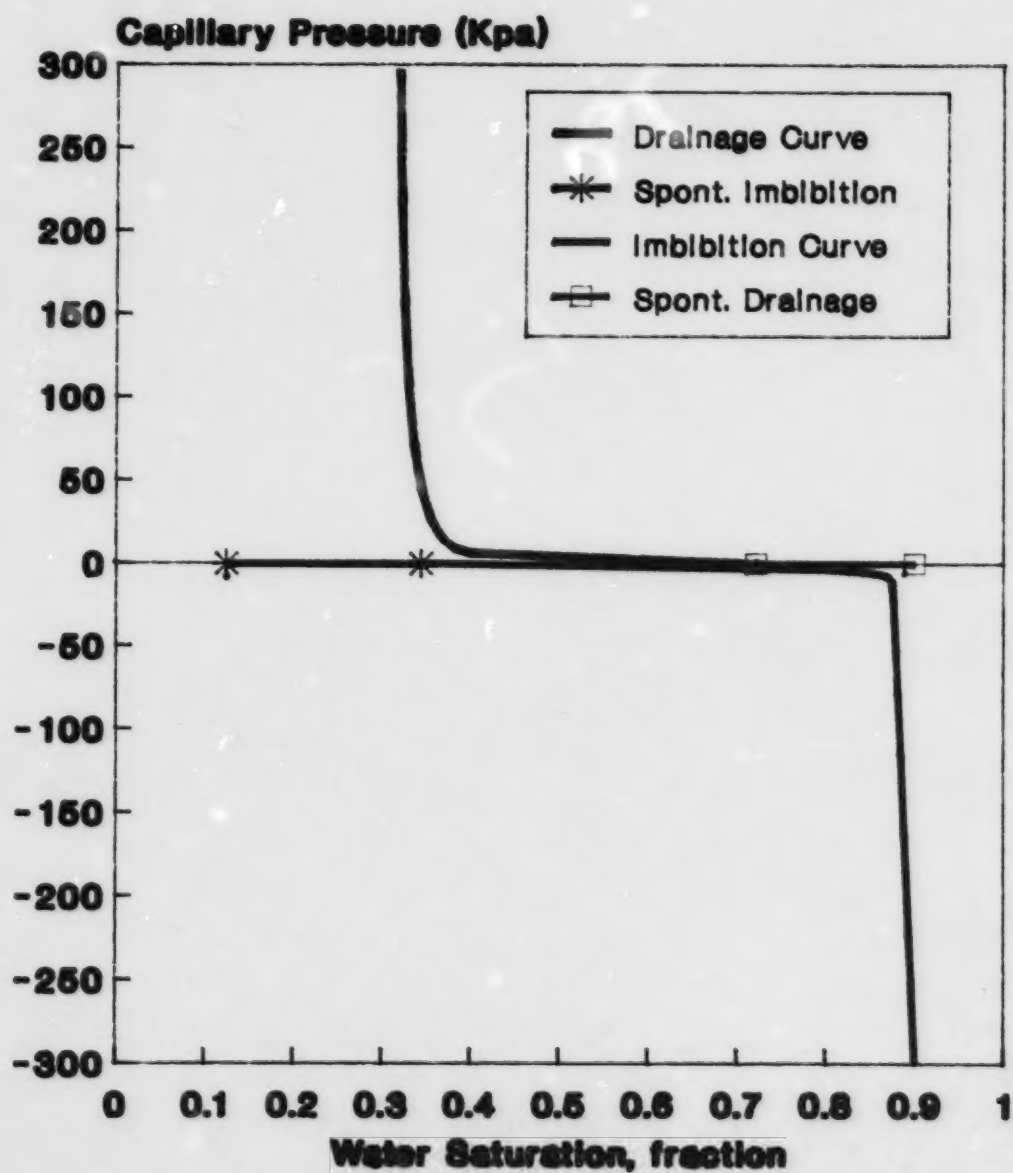


test performed at 87 C

Figure 40: Water/oil capillary pressure curve Baker 06.

Capillary Pressure Curves

Rainbow Keg River / 9-28: #2A - RESTORED

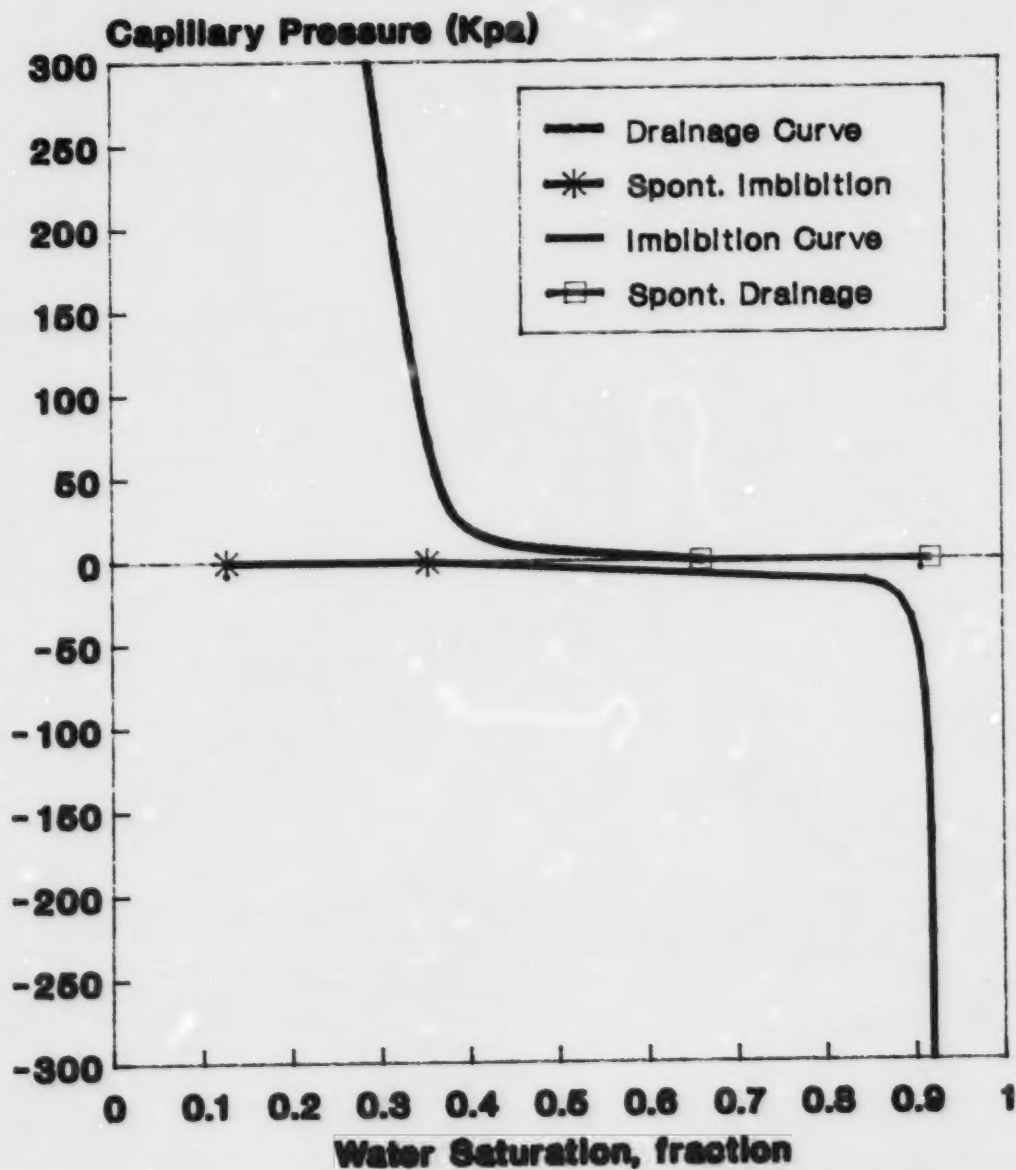


test performed at 87 C / Aged under oil

Figure 41: Water/oil capillary pressure curve 9-28/2A (restored).

Capillary Pressure Curves

Rainbow Keg River/9-28: #3A - RESTORED

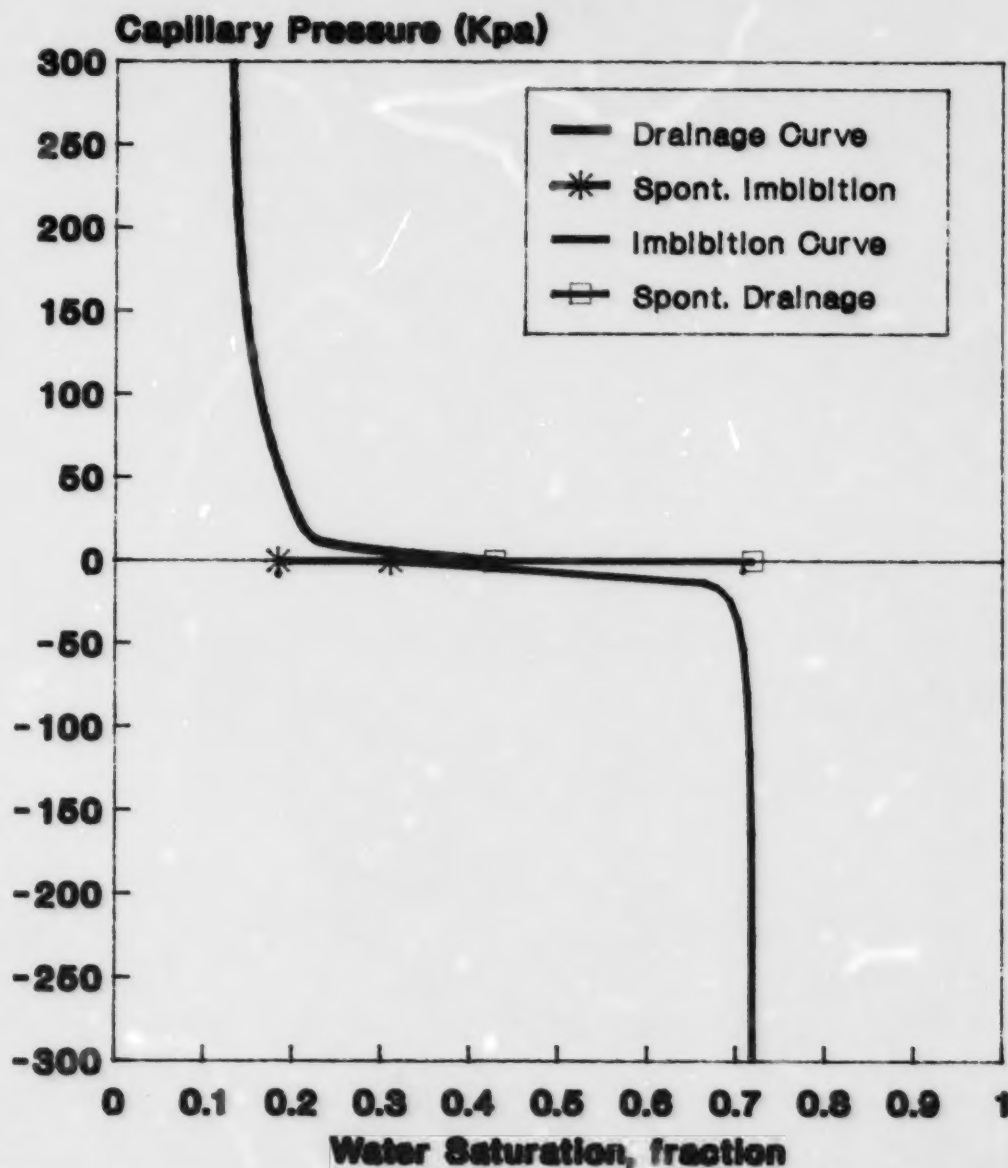


test performed at 87 C / Aged under oil

Figure 42: Water/oil capillary pressure curve 9-28/3A (restored).

Capillary Pressure Curves

Rainbow Keg River / 9-28:#10A - RESTORED



test performed at 87 C / Aged under oil

Figure 43: Water/oil capillary pressure curve 9-28/10A (restored).

Gas

9-28/2A

Oil, gas and water saturation

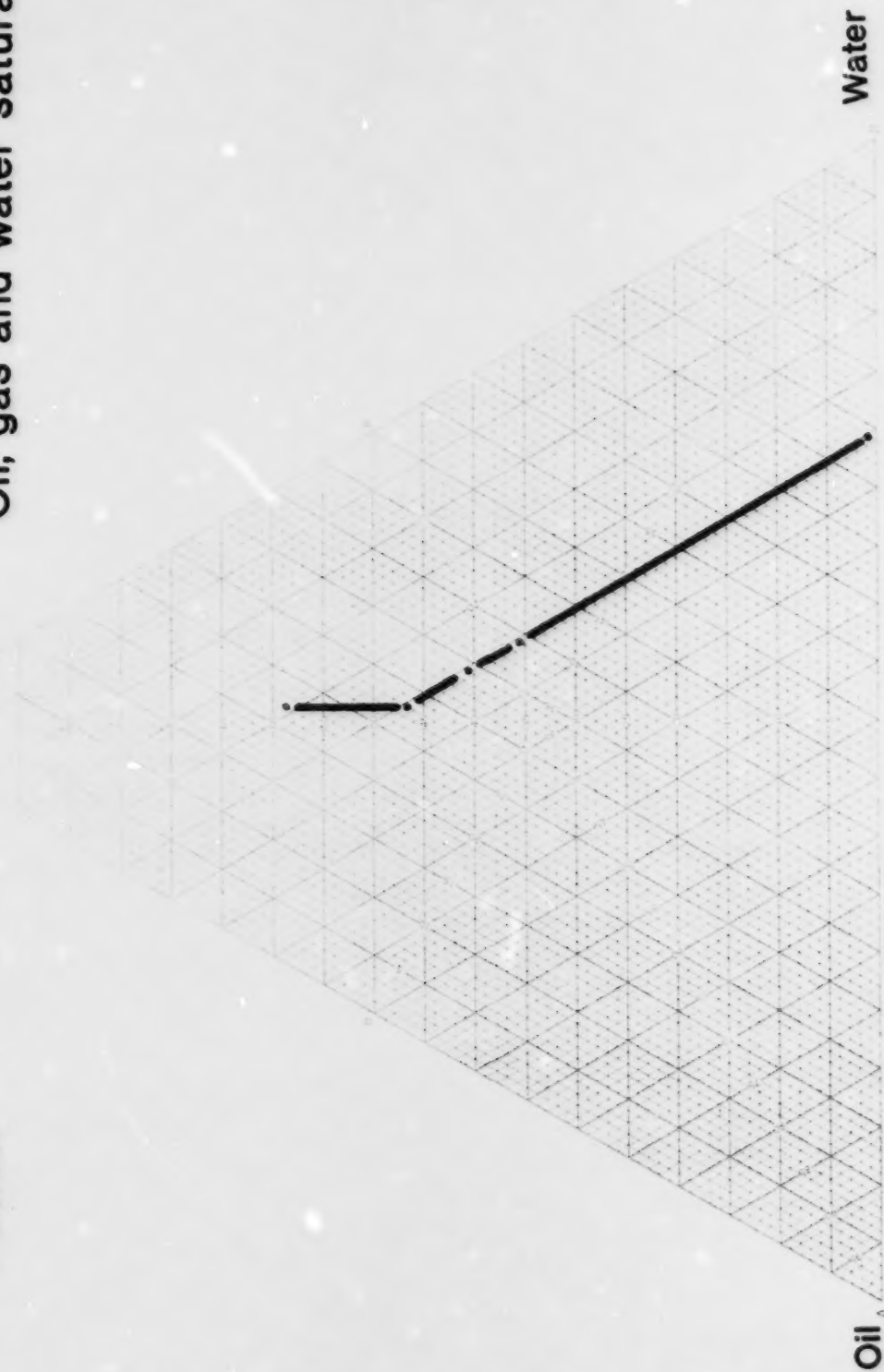


Figure 44: Ternary diagram for gas injection in 9-28/2A.

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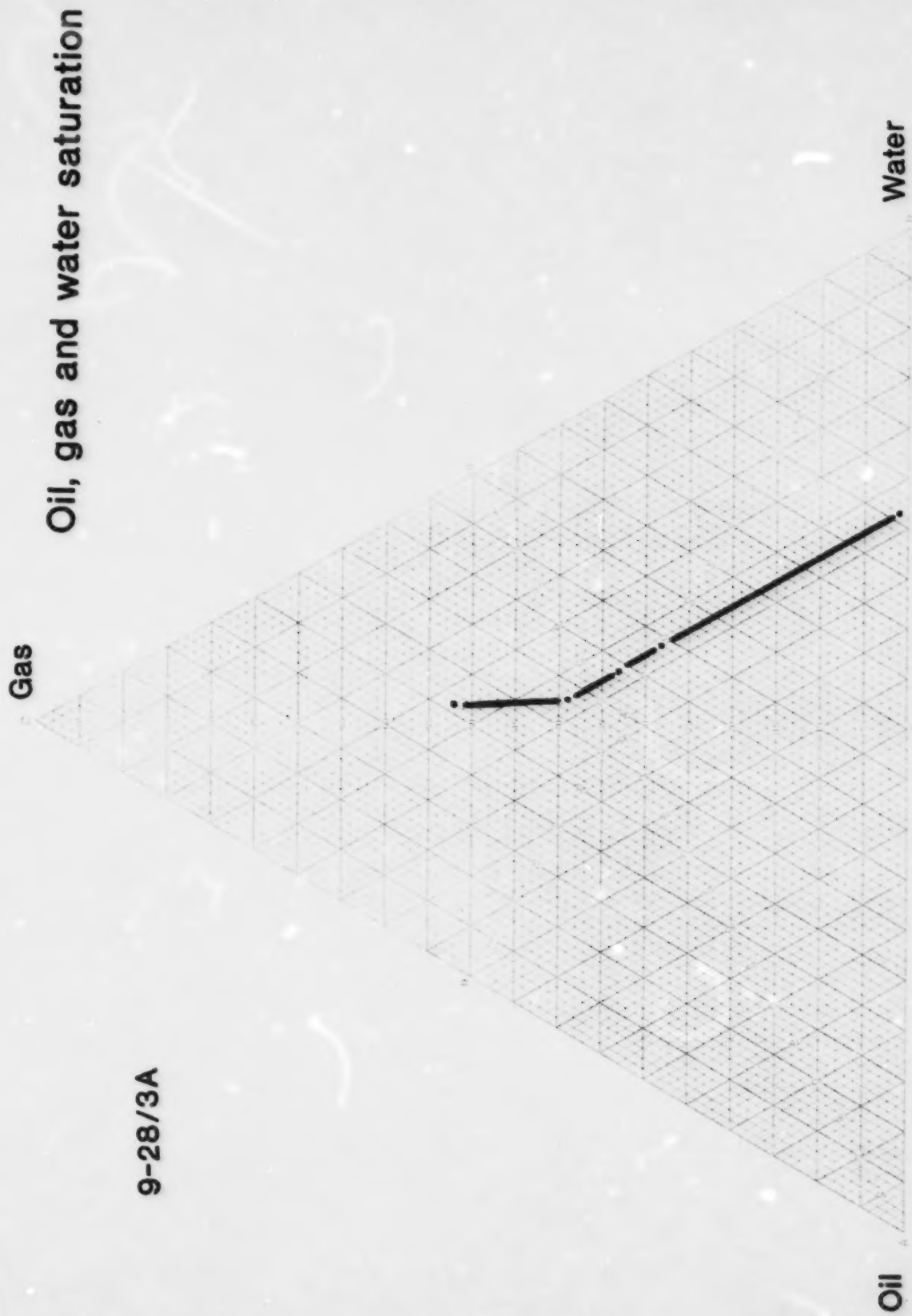


Figure 45: Ternary diagram for gas injection in 9-28/3A.

Gas

Oil, gas and water saturation

9-28/8A



Figure 46: Ternary diagram for gas injection in 9-28/8A.

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Gas

Oil, gas and water saturation

9-28/1A



Figure 47: Ternary diagram for gas injection in 9-28/1A.

Gas

Oil, gas and water saturation

9-28/10A

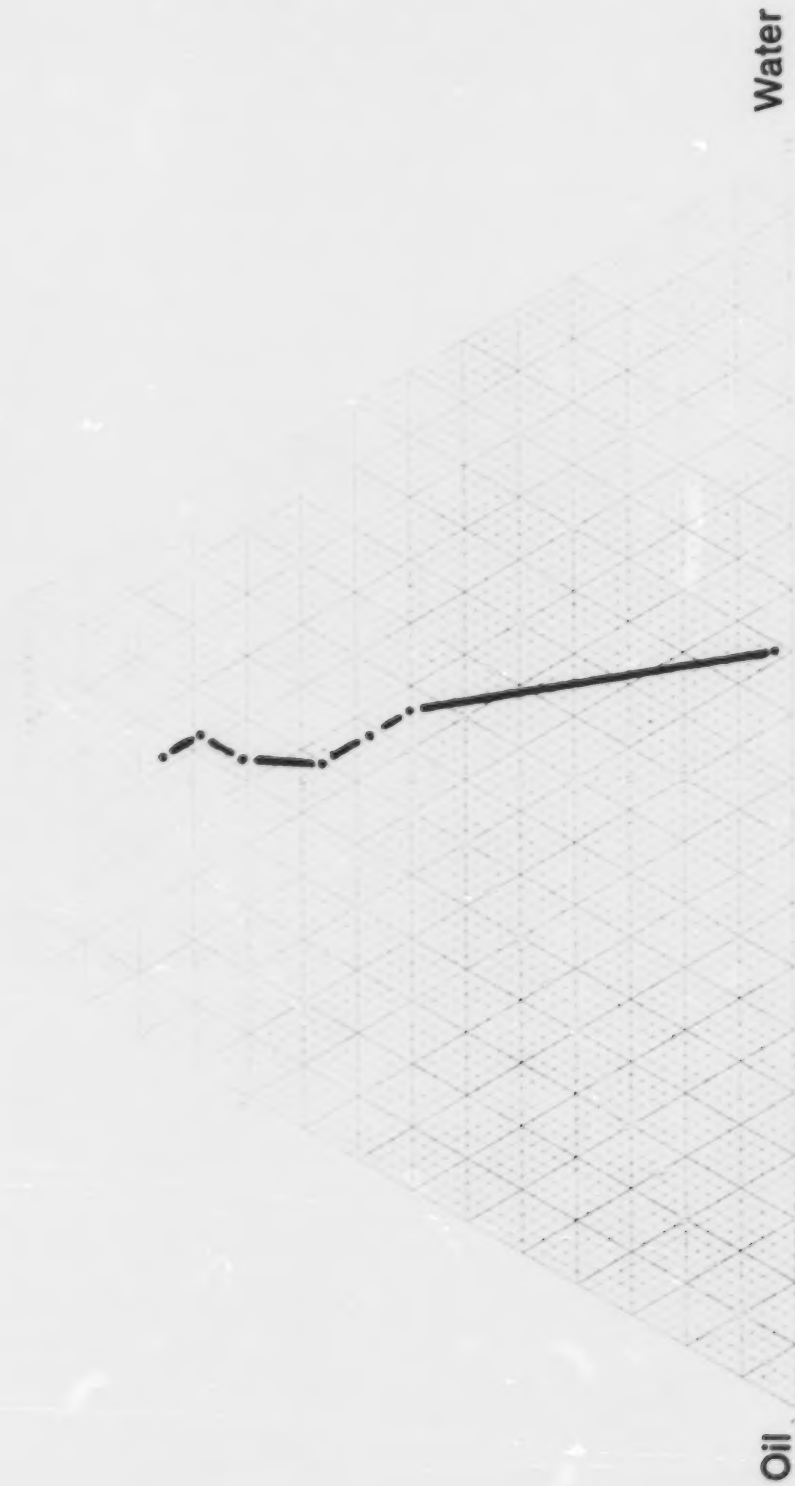


Figure 48: Ternary diagram for gas injection in 9-28/10A.

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Gas

Oil, gas and water saturation

9-28/11A

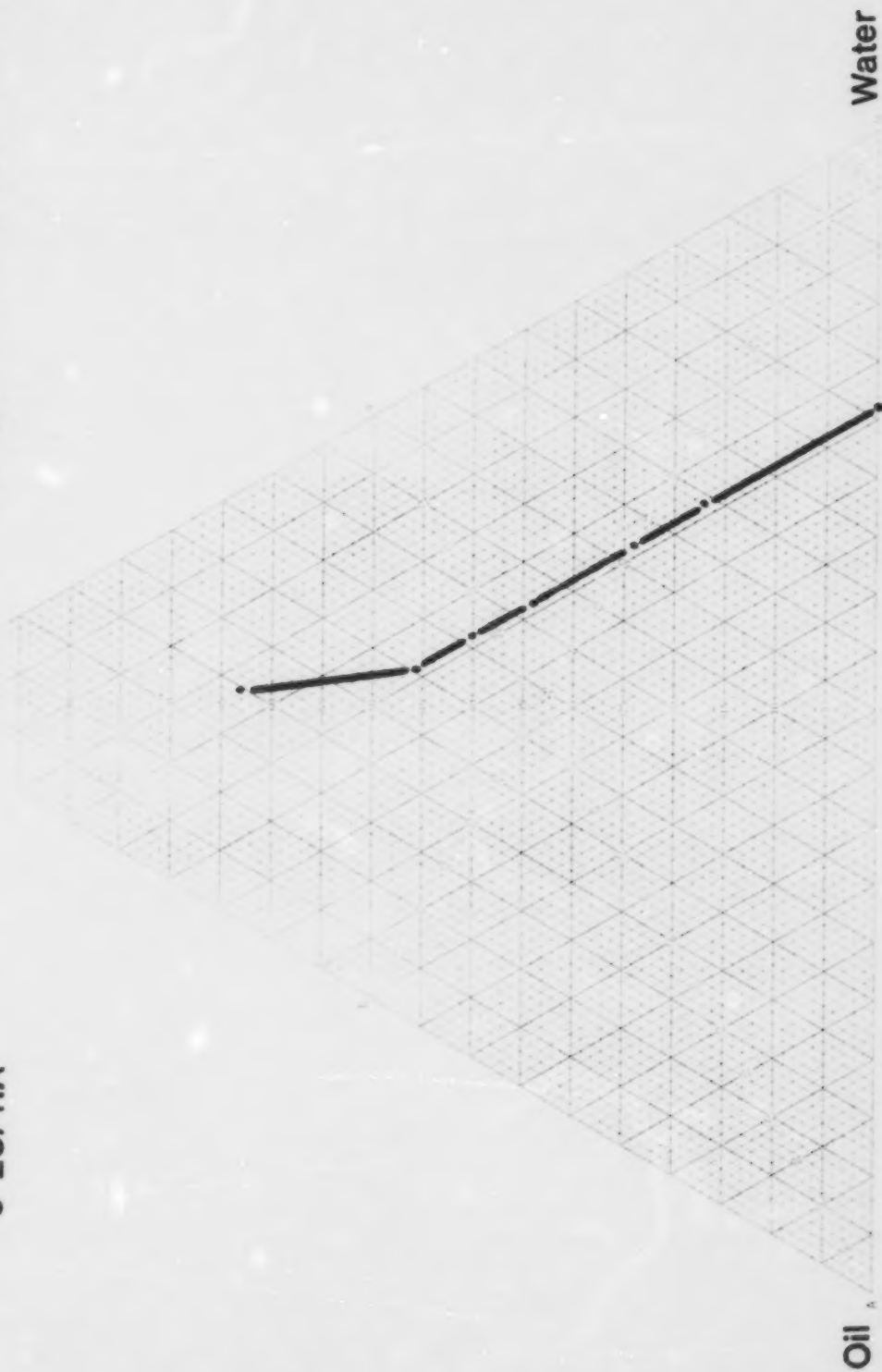


Figure 49: Ternary diagram for gas injection in 9-28/11A.

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Gas

9-28/14A

Oil, gas and water saturation



Figure 50: Ternary diagram for gas injection in 9-28/14A.

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Gas

Oil, gas and water saturation

6-6/1A

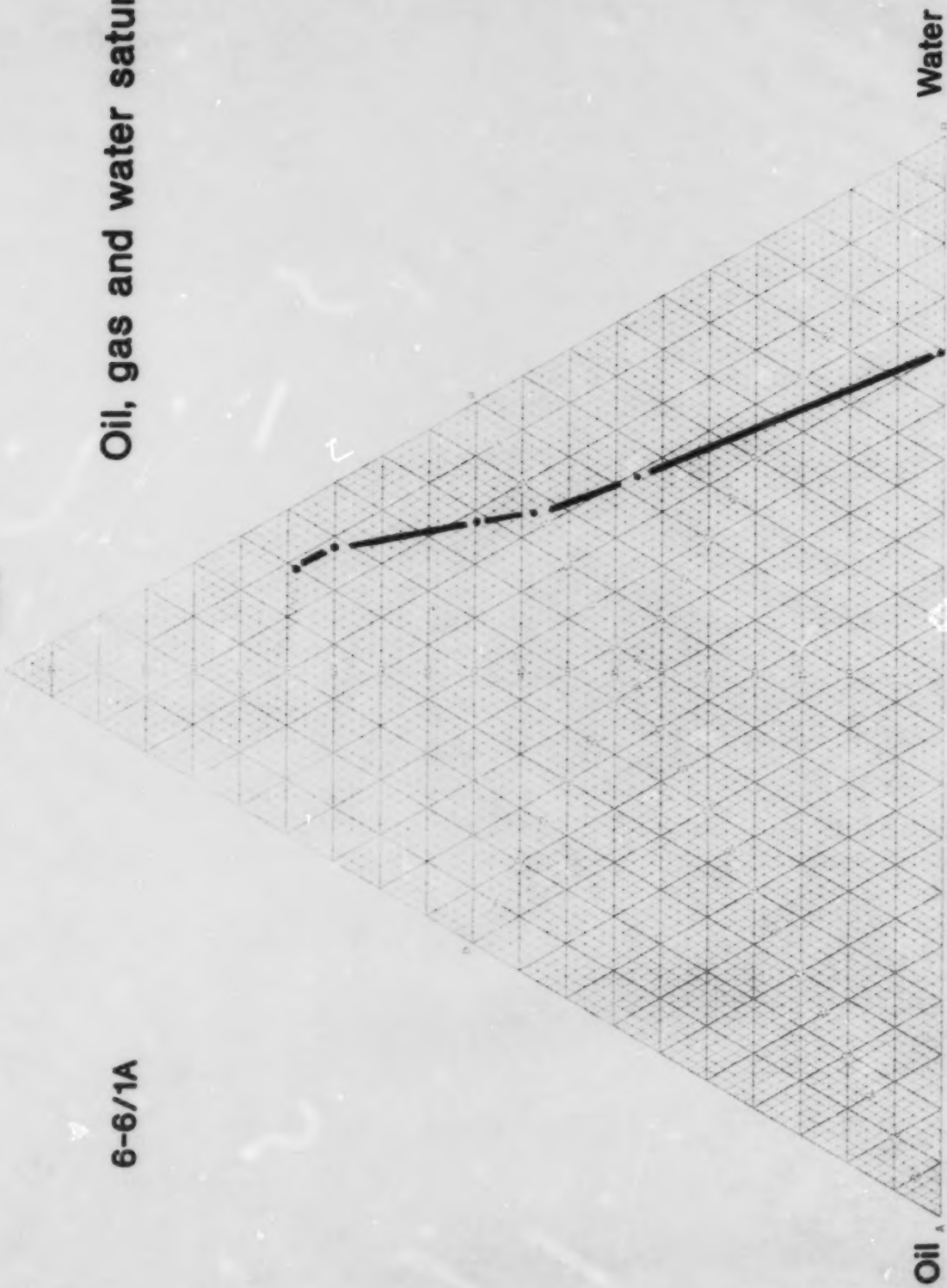


Figure 51: Ternary diagram for gas injection in 6-6/1A.

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Gas

G-6/2A

Oil, gas and water saturation

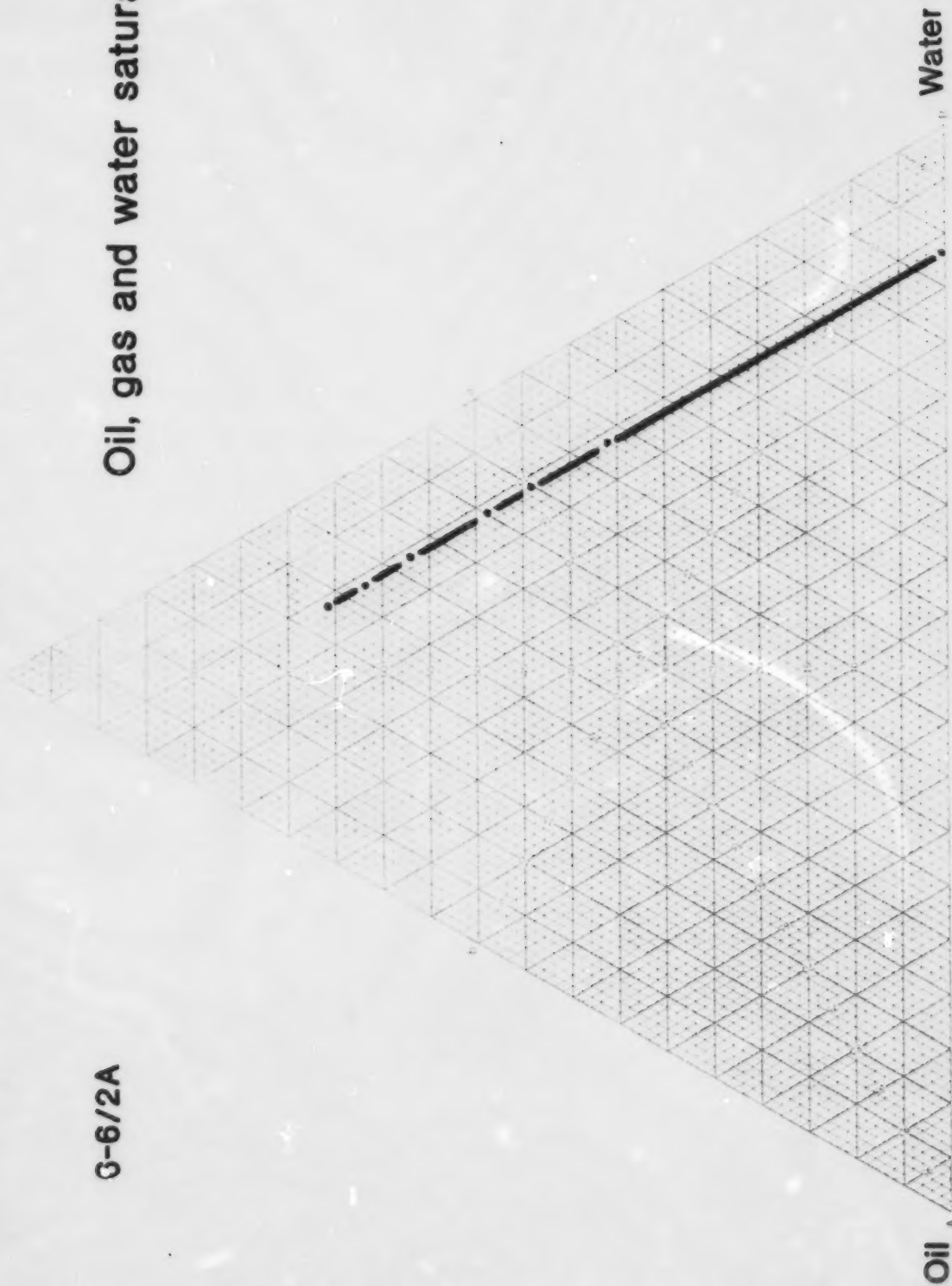


Figure 52: Ternary diagram for gas injection in G-6/2A.

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6-6/4A

Gas

Oil, gas and water saturation

Water

Oil

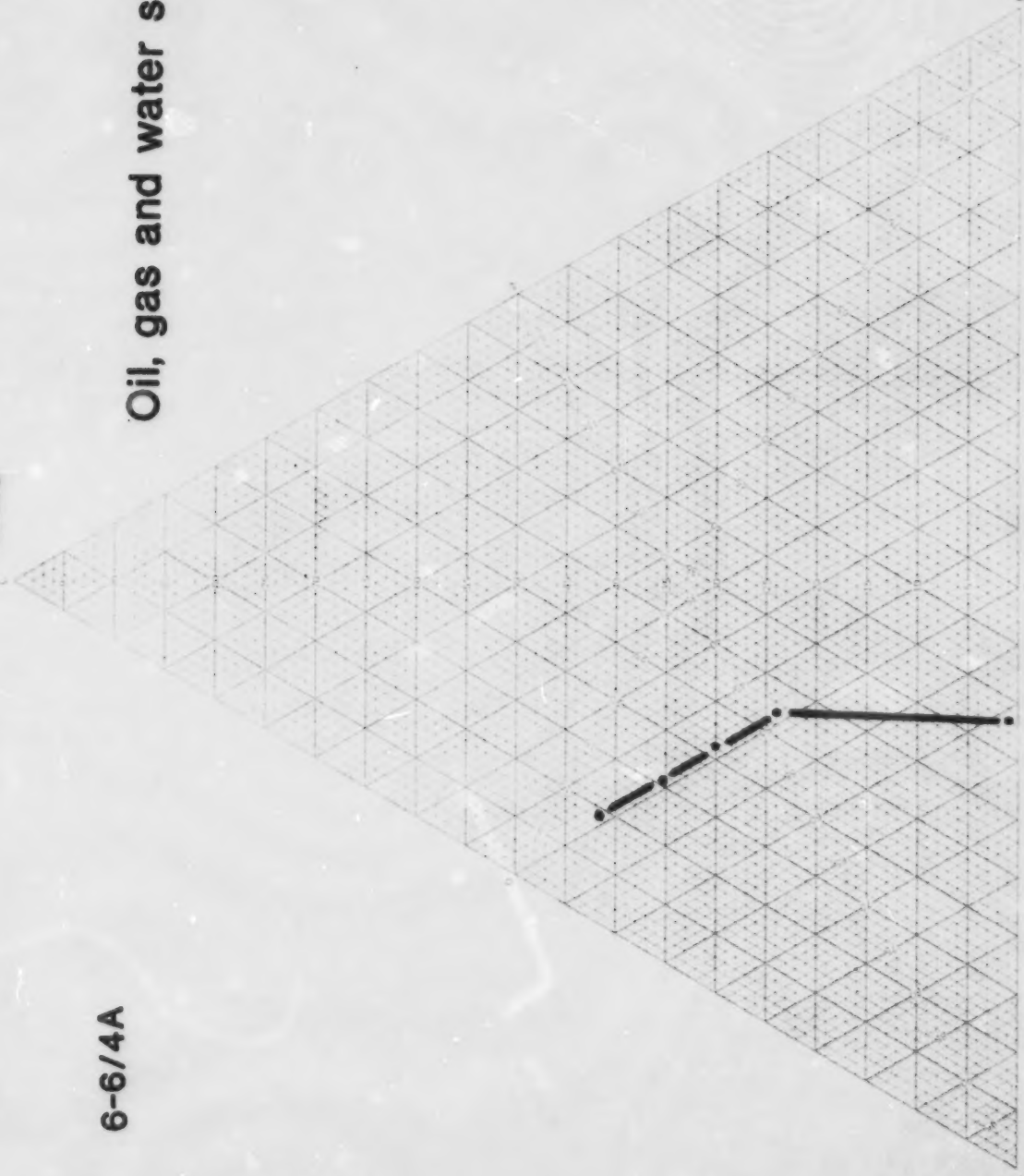


Figure 53: Ternary diagram for gas injection in 6-6/4A.

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Gas

6-6/5A

Oil, gas and water saturation

Water

Oil

Figure 54: Ternary diagram for gas injection in 6-6/5A.

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Gas

Oil, gas and water saturation

Berea sandstone

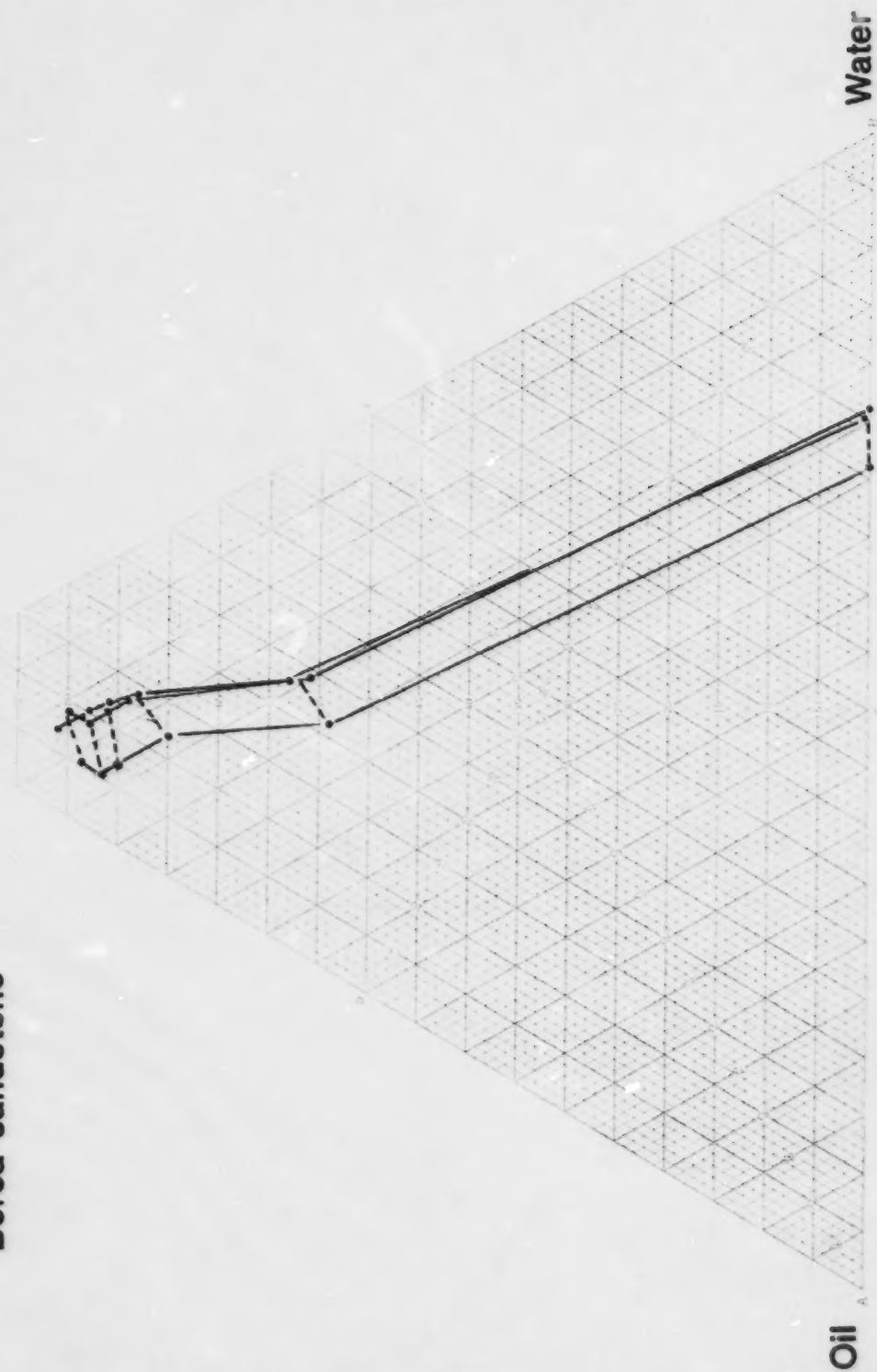


Figure 55: Ternary diagram for gas injection in Berea.

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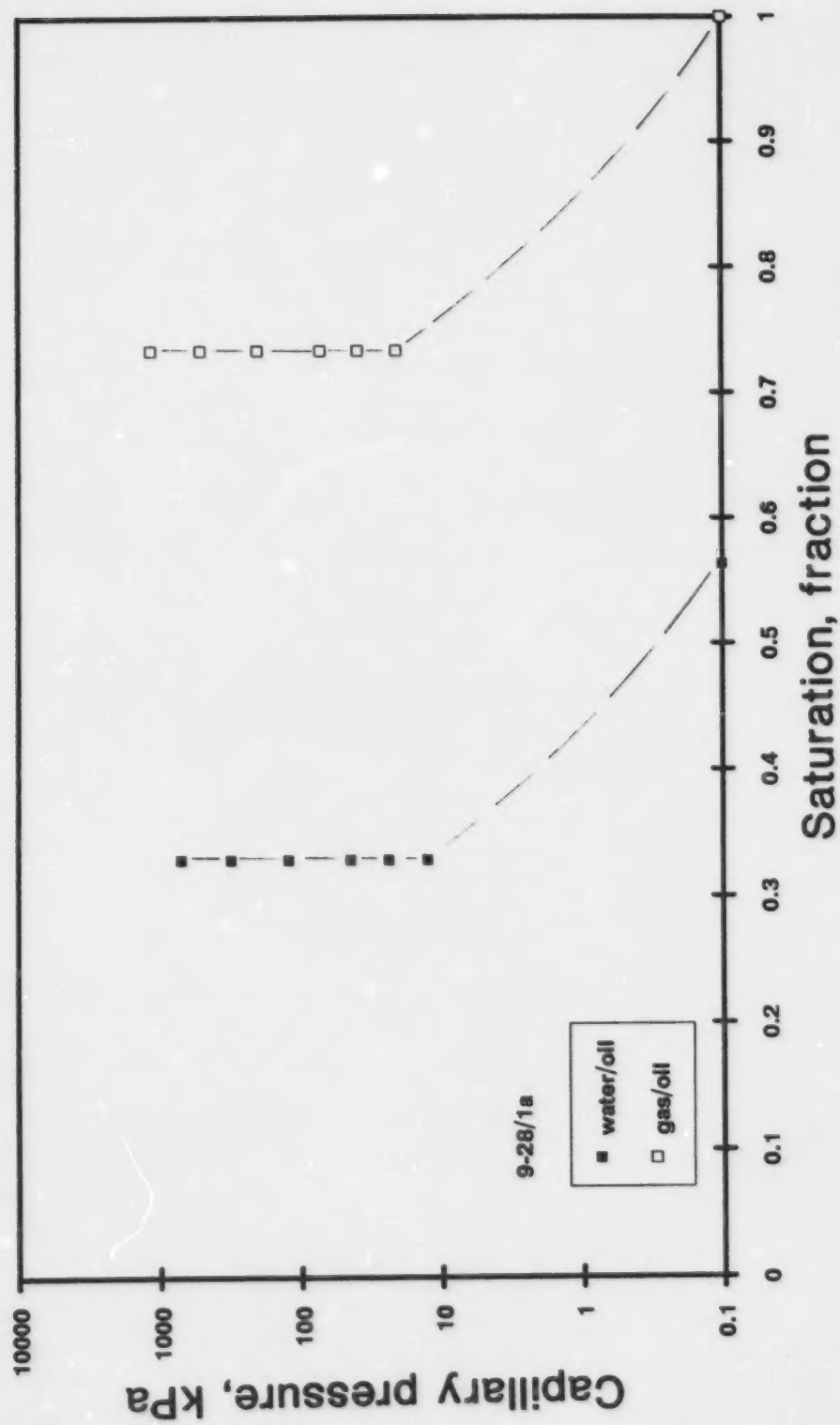


Figure 56: Proposed capillary pressure scheme for gas injection 9-28/1A.

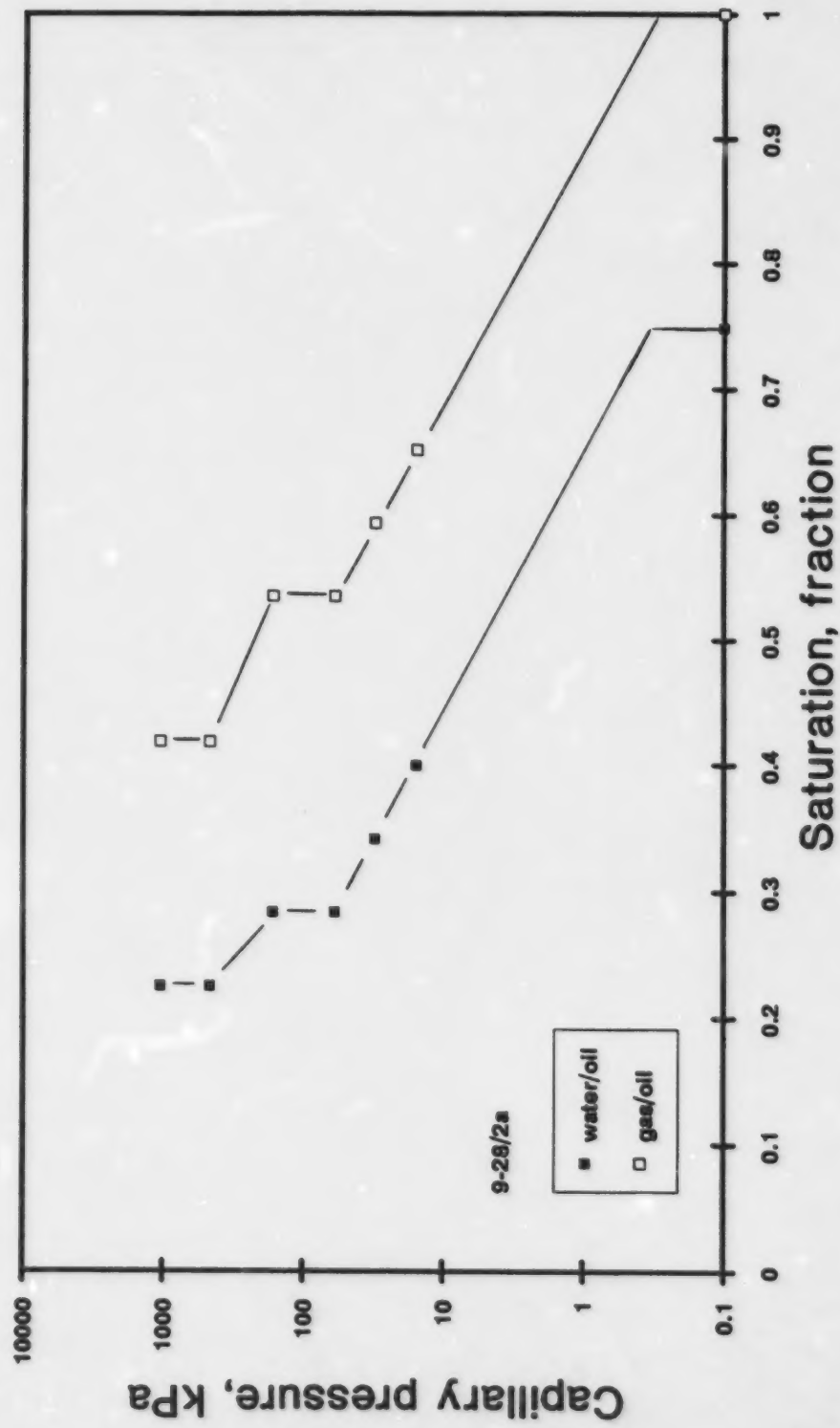


Figure 57: Proposed capillary pressure scheme for gas injection 9-28/2A.

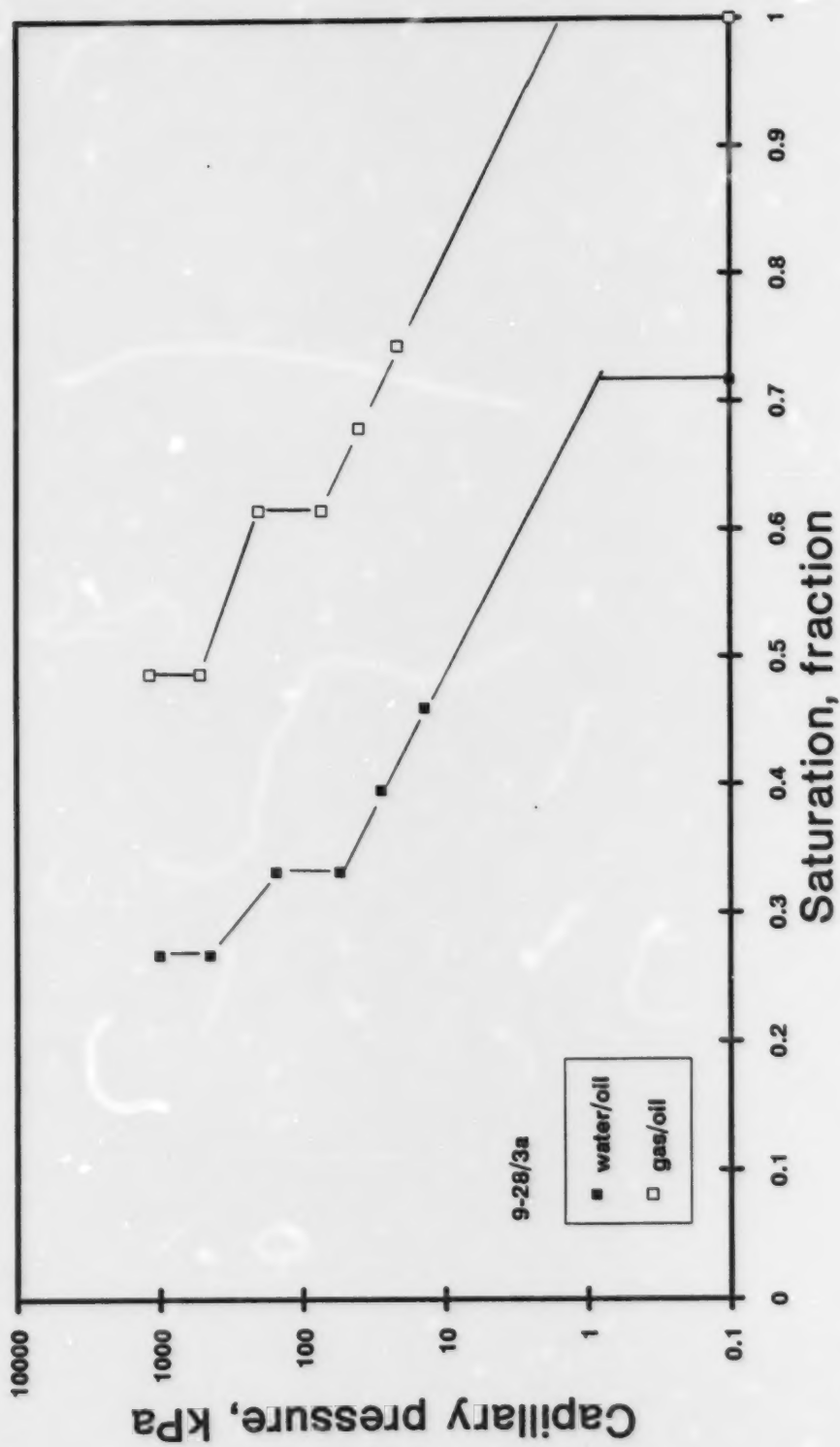


Figure 58: Proposed capillary pressure scheme for gas injection 9-28/3A.

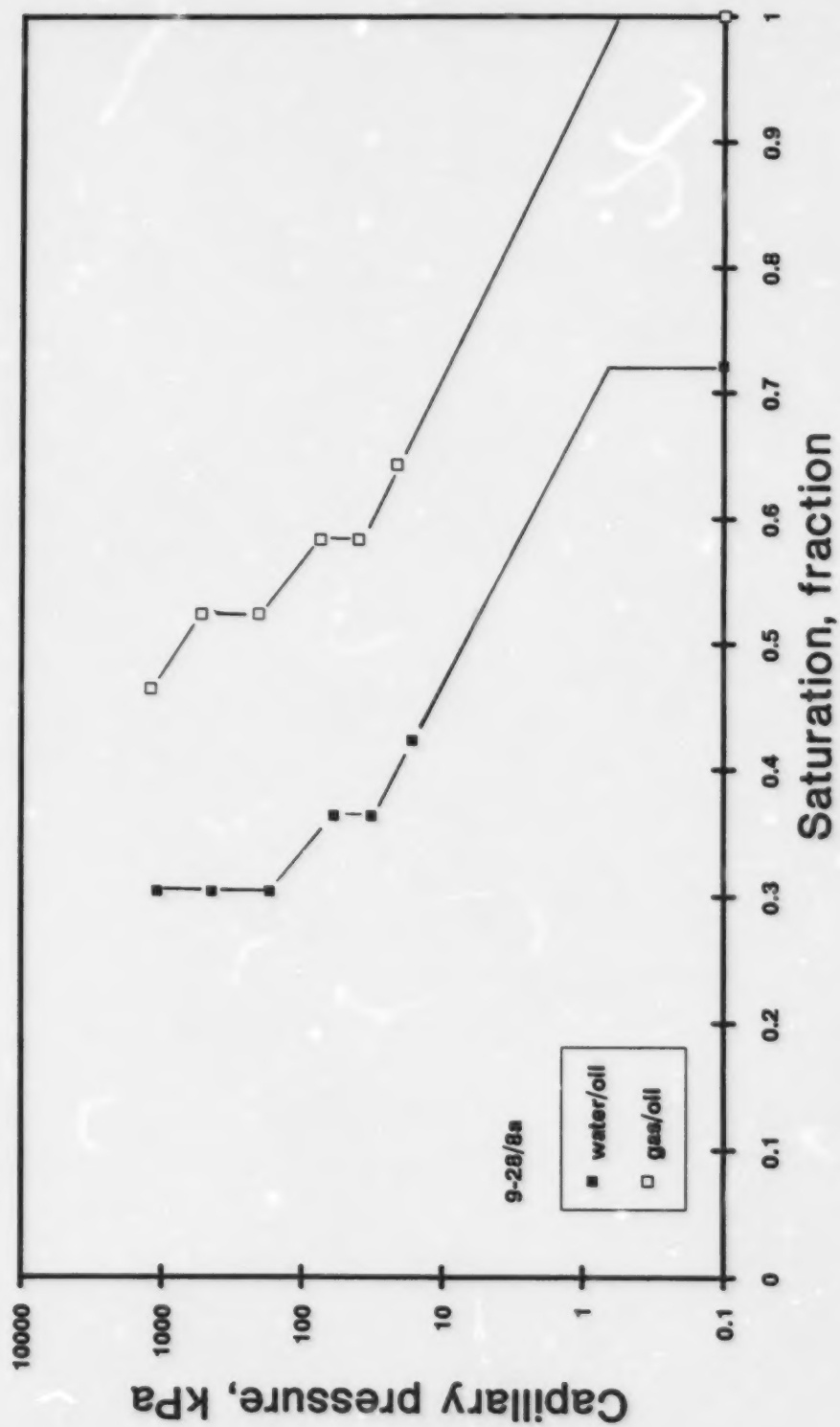


Figure 59: Proposed capillary pressure scheme for gas injection 9-28/8A.

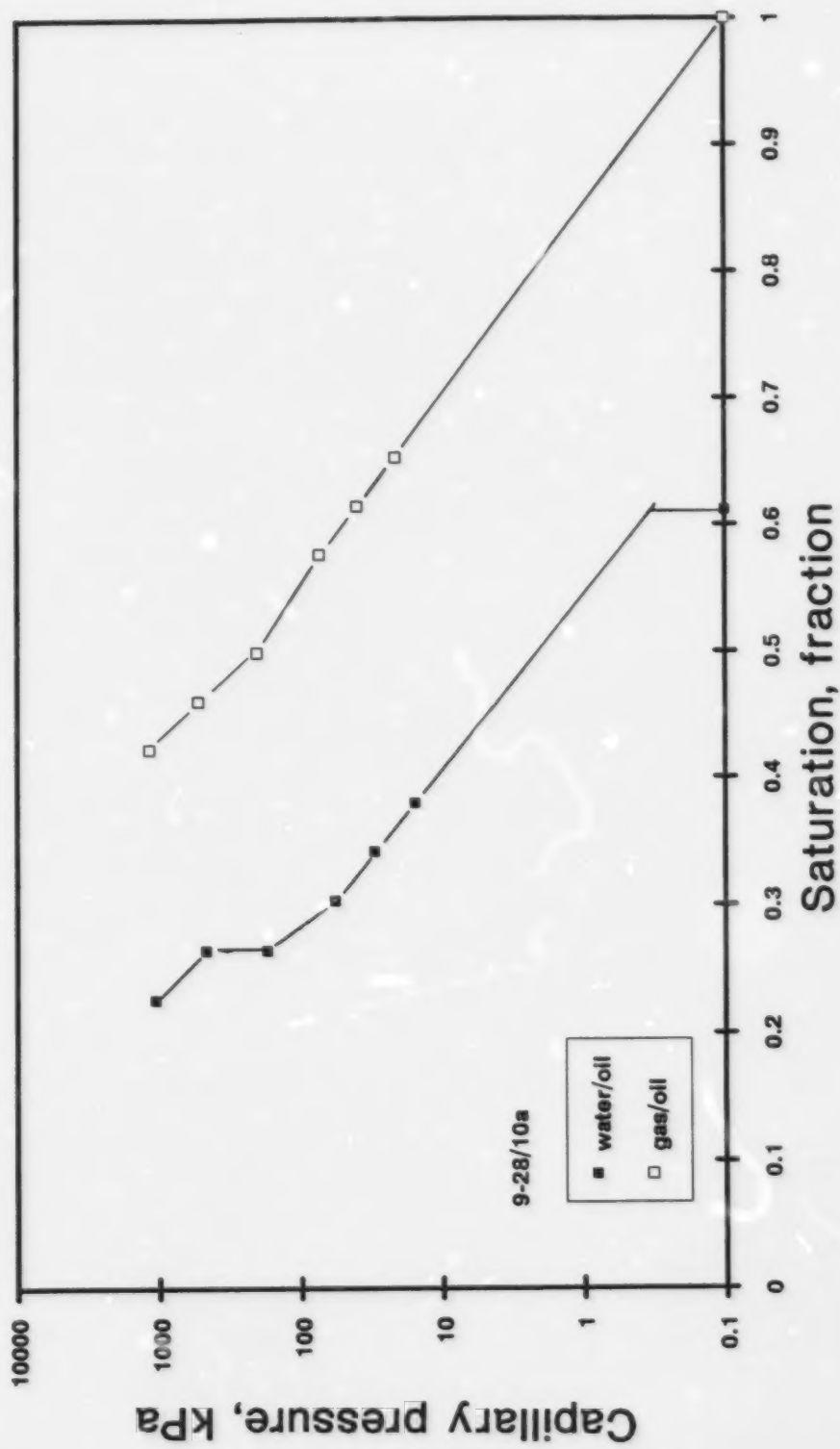


Figure 60: Proposed capillary pressure scheme for gas Injection 9-28/10A.

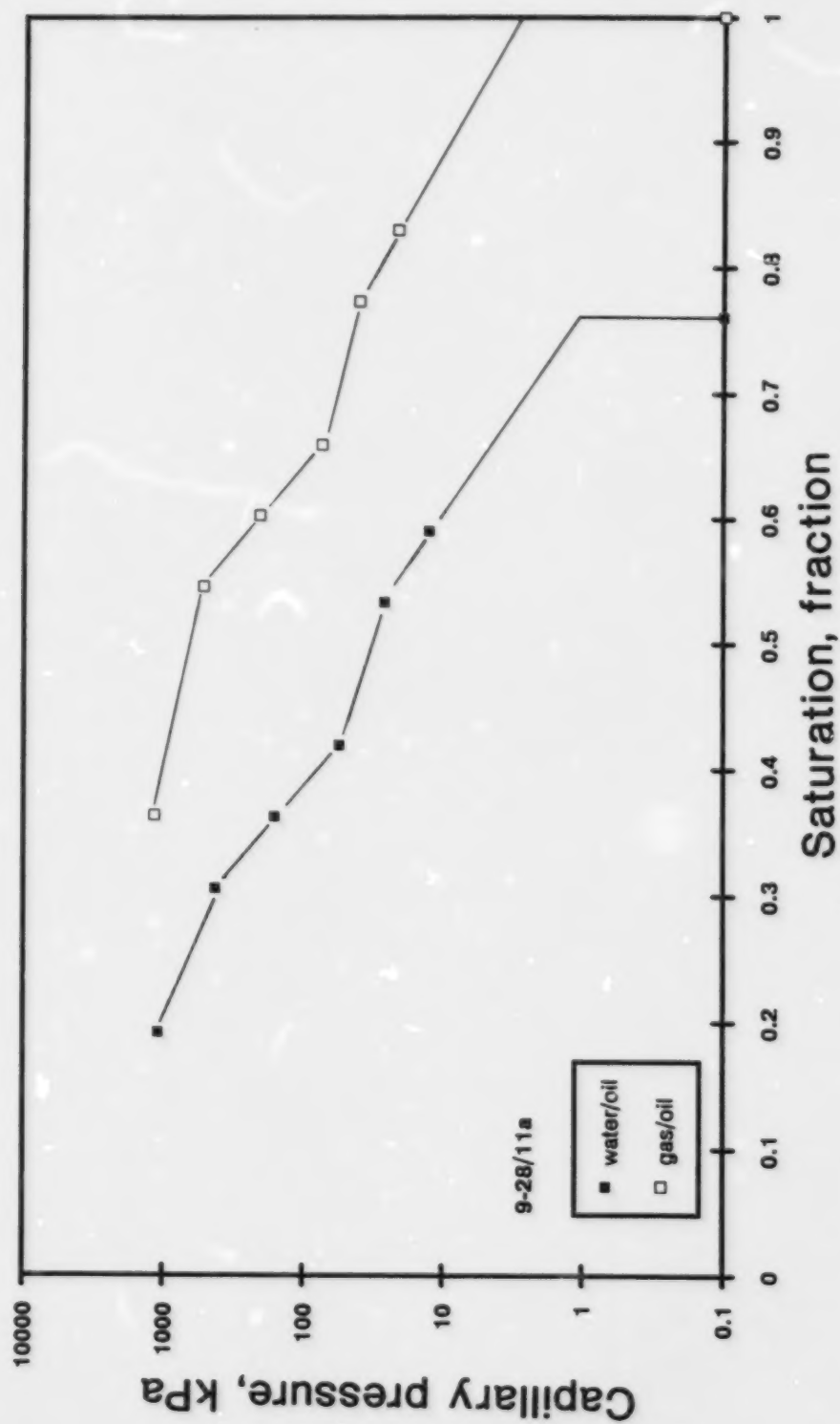


Figure 61: Proposed capillary pressure scheme for gas injection 9-28/11A.

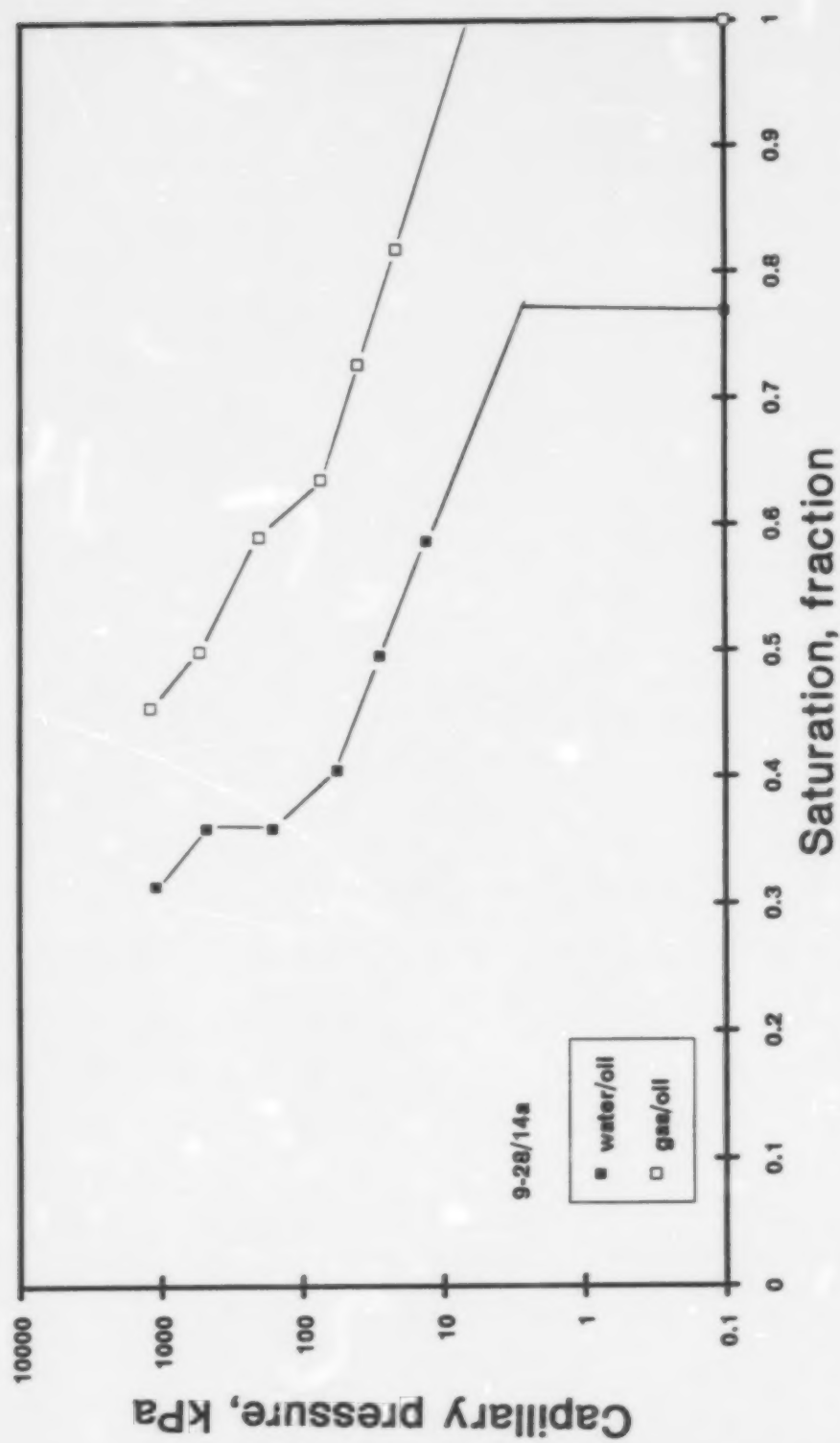


Figure 62: Proposed capillary pressure scheme for gas injection 9-28/14A.

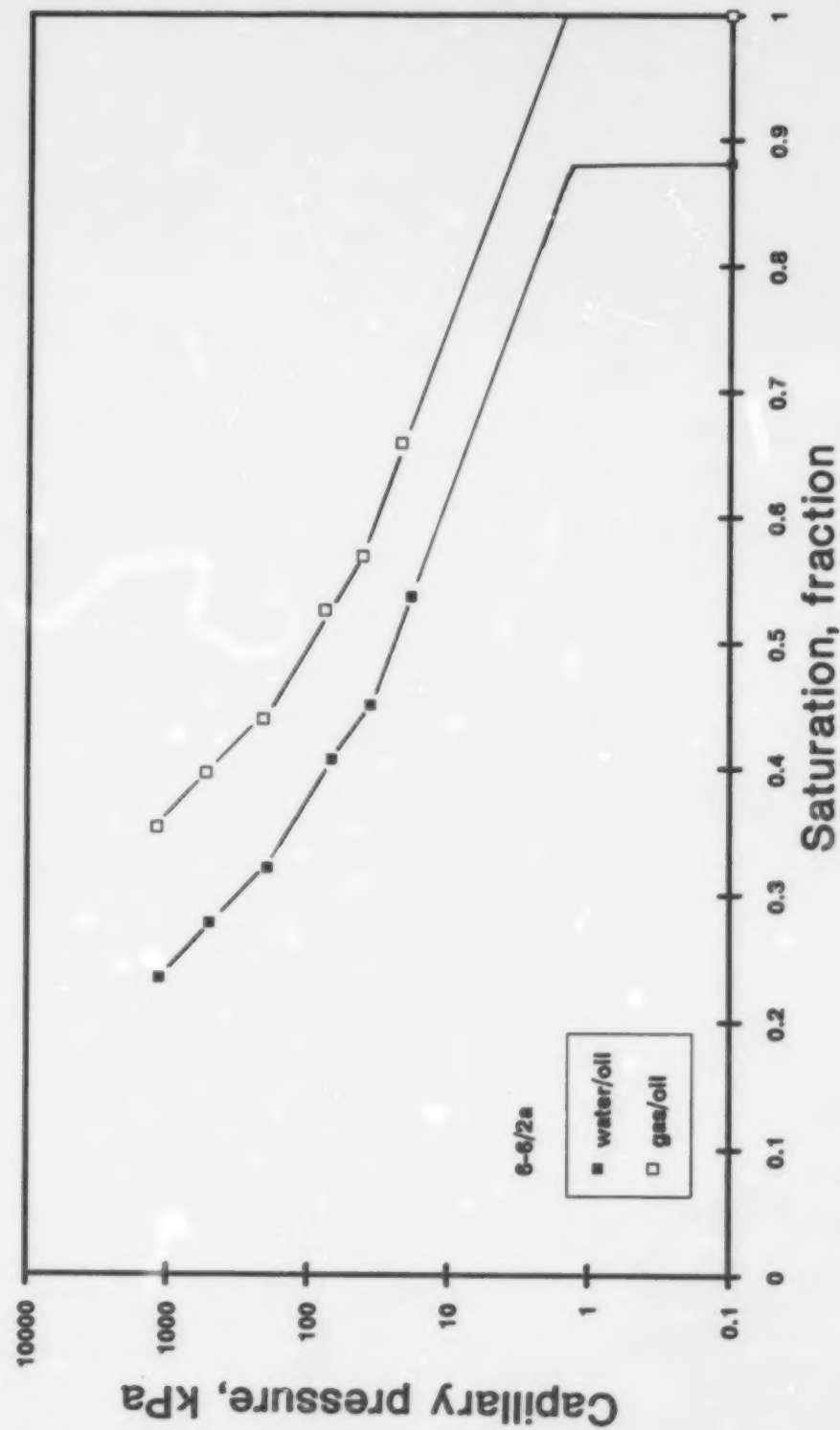


Figure 63: Proposed capillary pressure scheme for gas injection 6-6/2A.

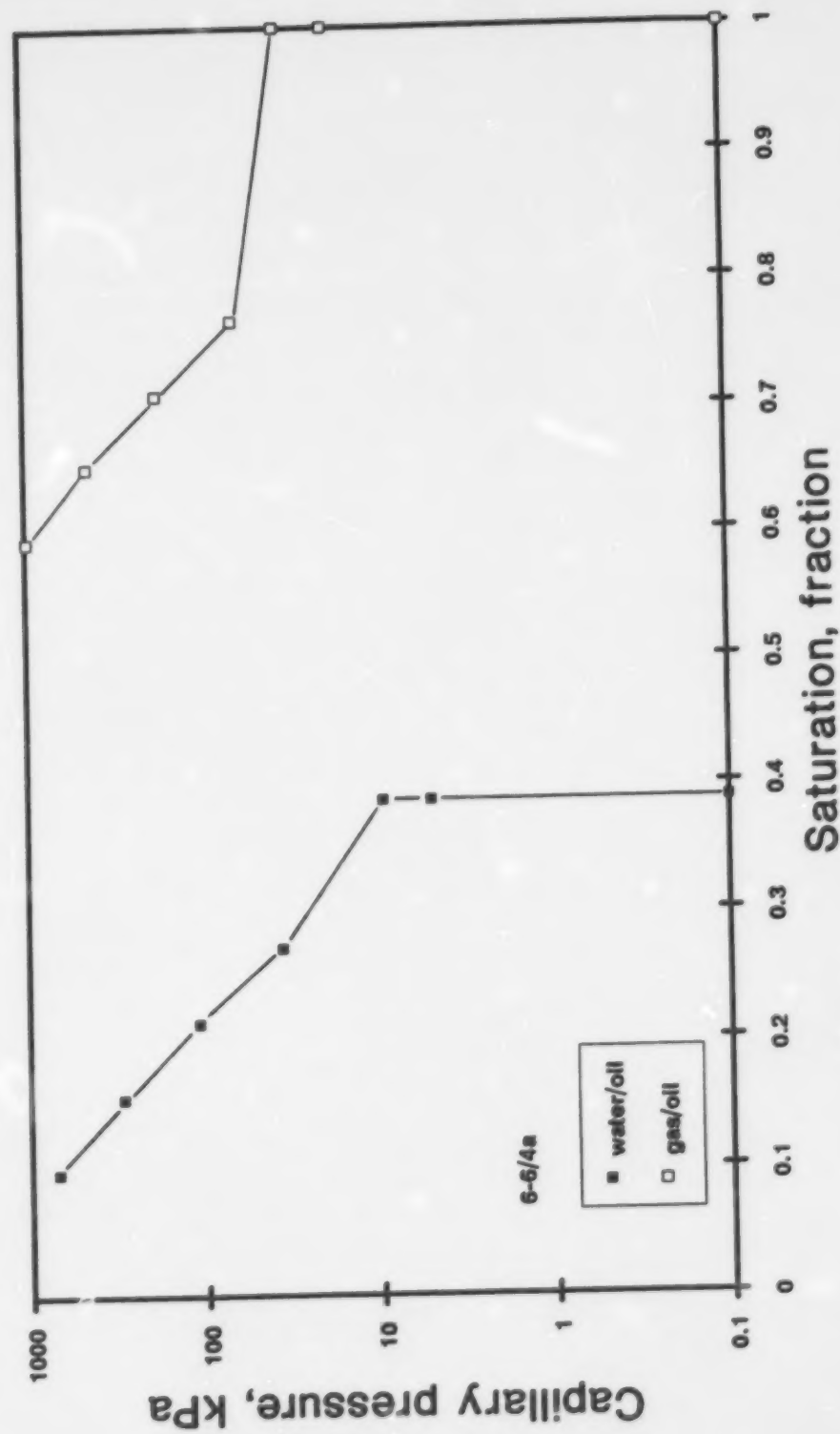


Figure 64: Proposed capillary pressure scheme for gas injection 6-6/4A.

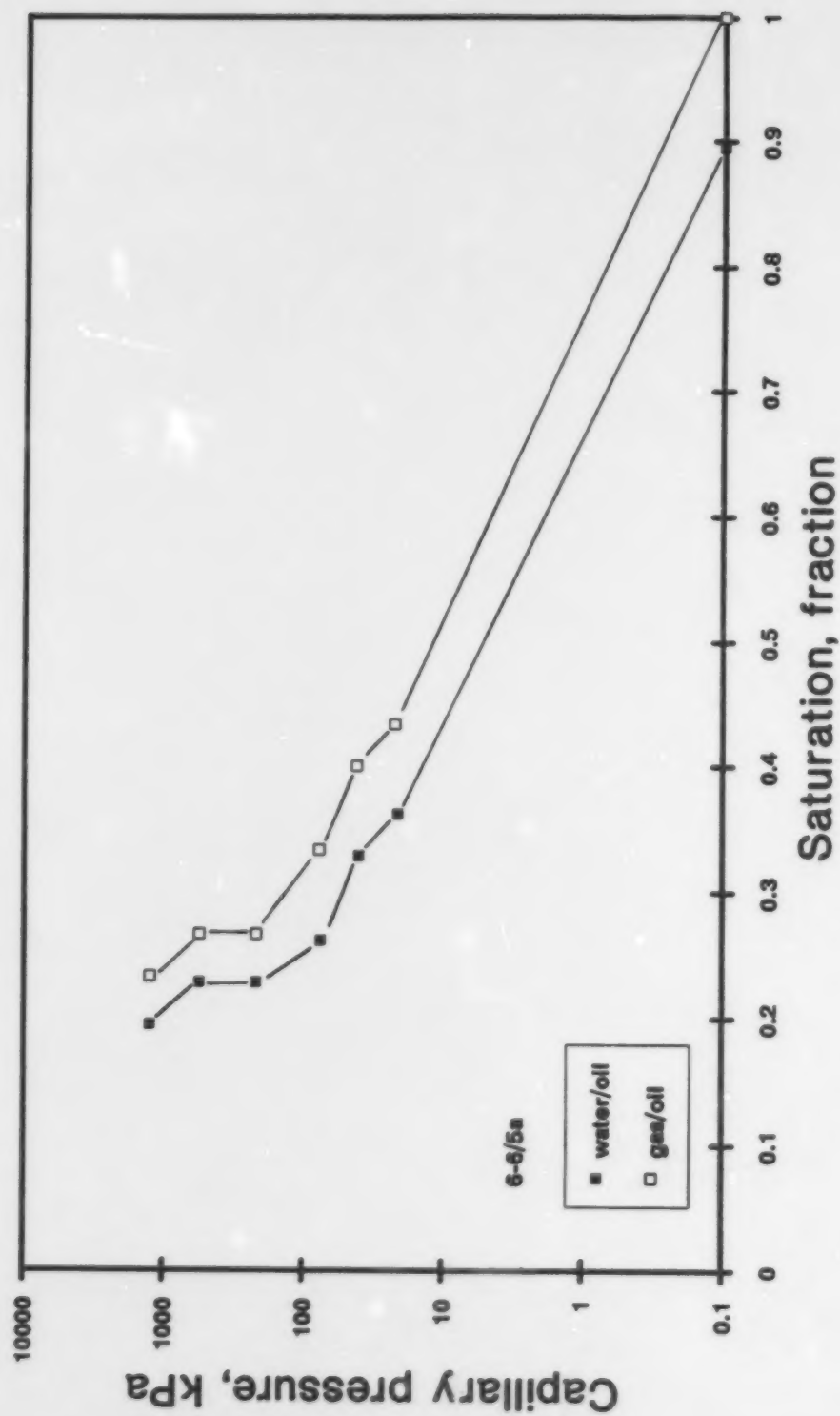


Figure 65: Proposed capillary pressure scheme for gas injection 6-6/5A.

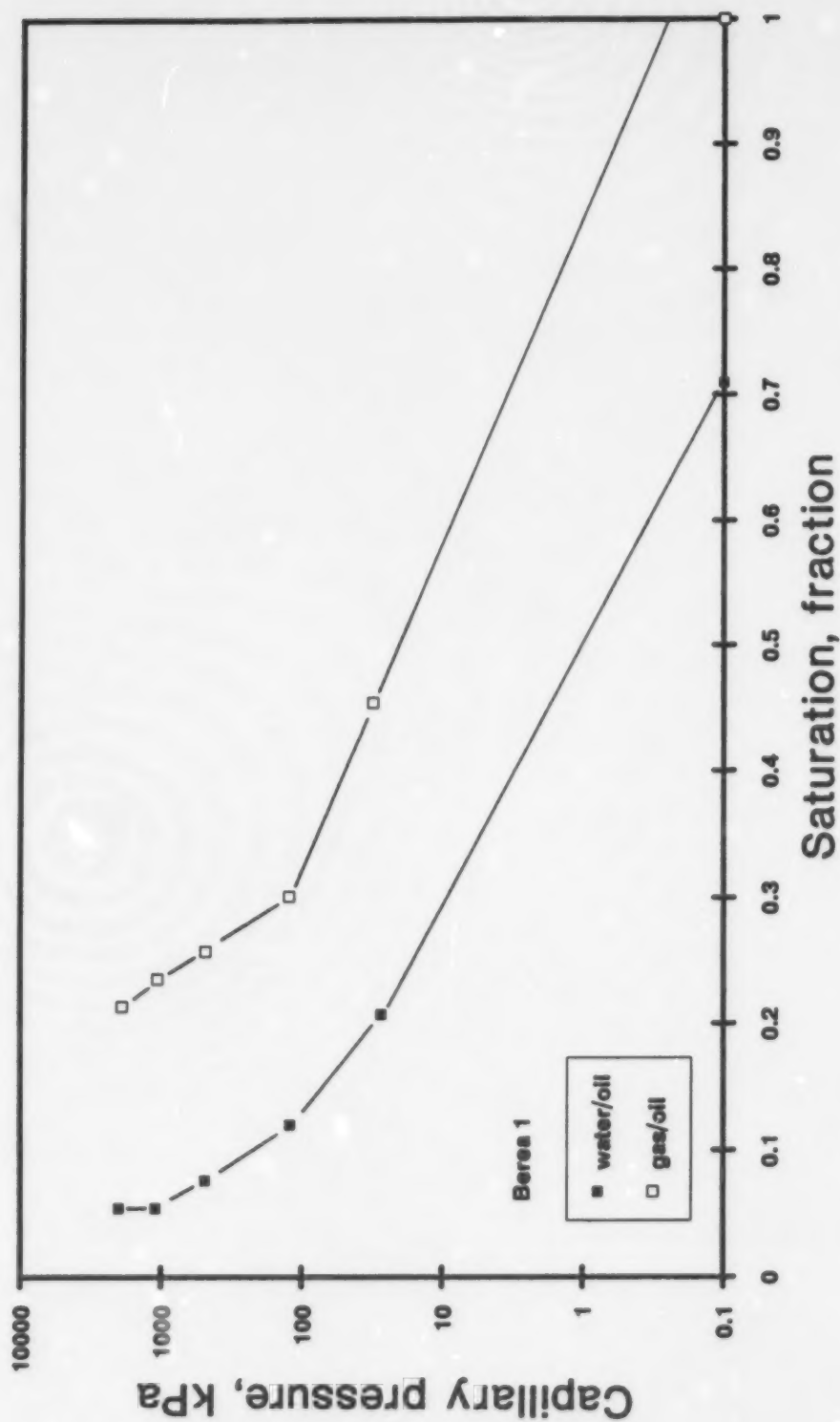


Figure 66: Proposed capillary pressure scheme for gas injection Berea 01.

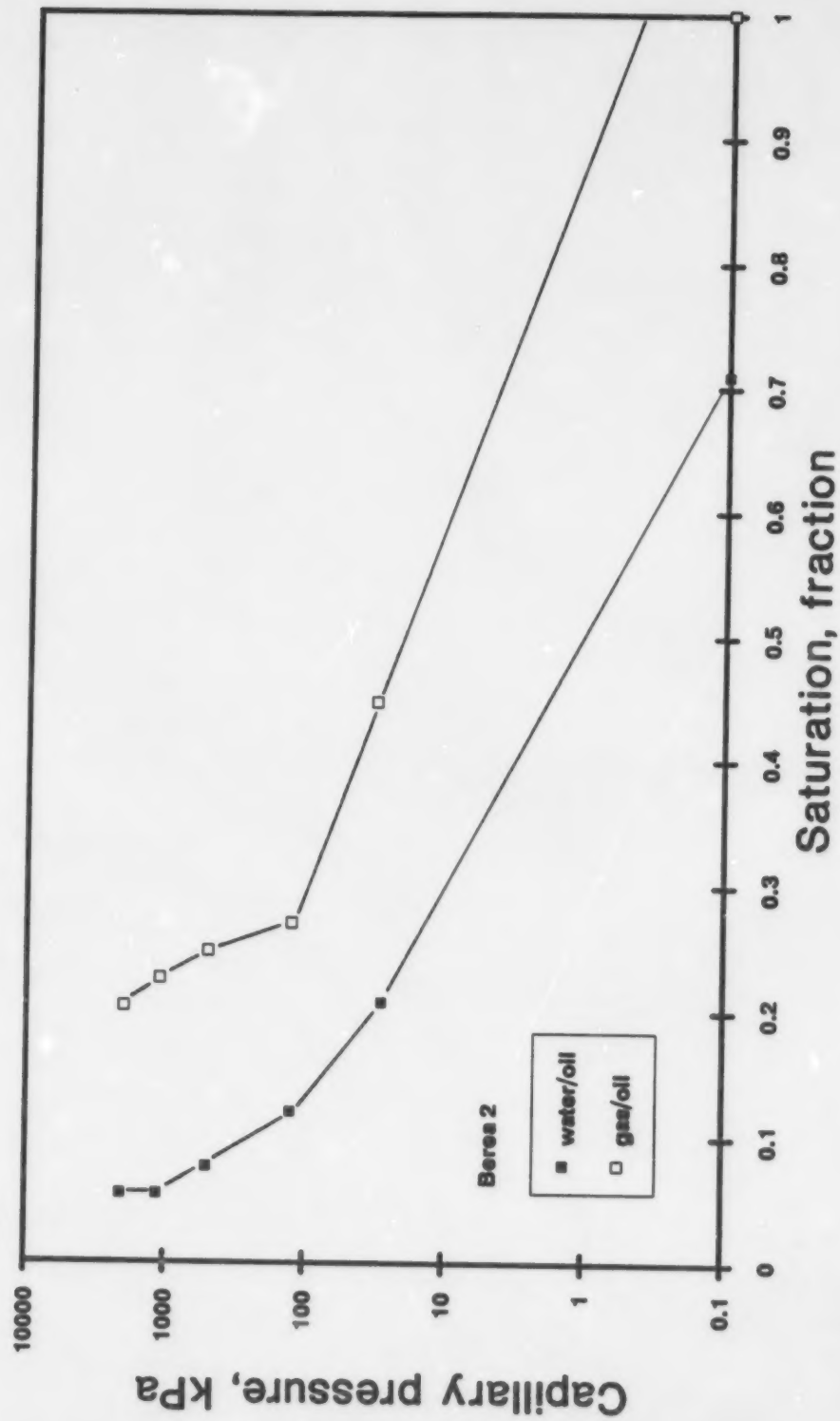


Figure 67: Proposed capillary pressure scheme for gas injection Berea 02.

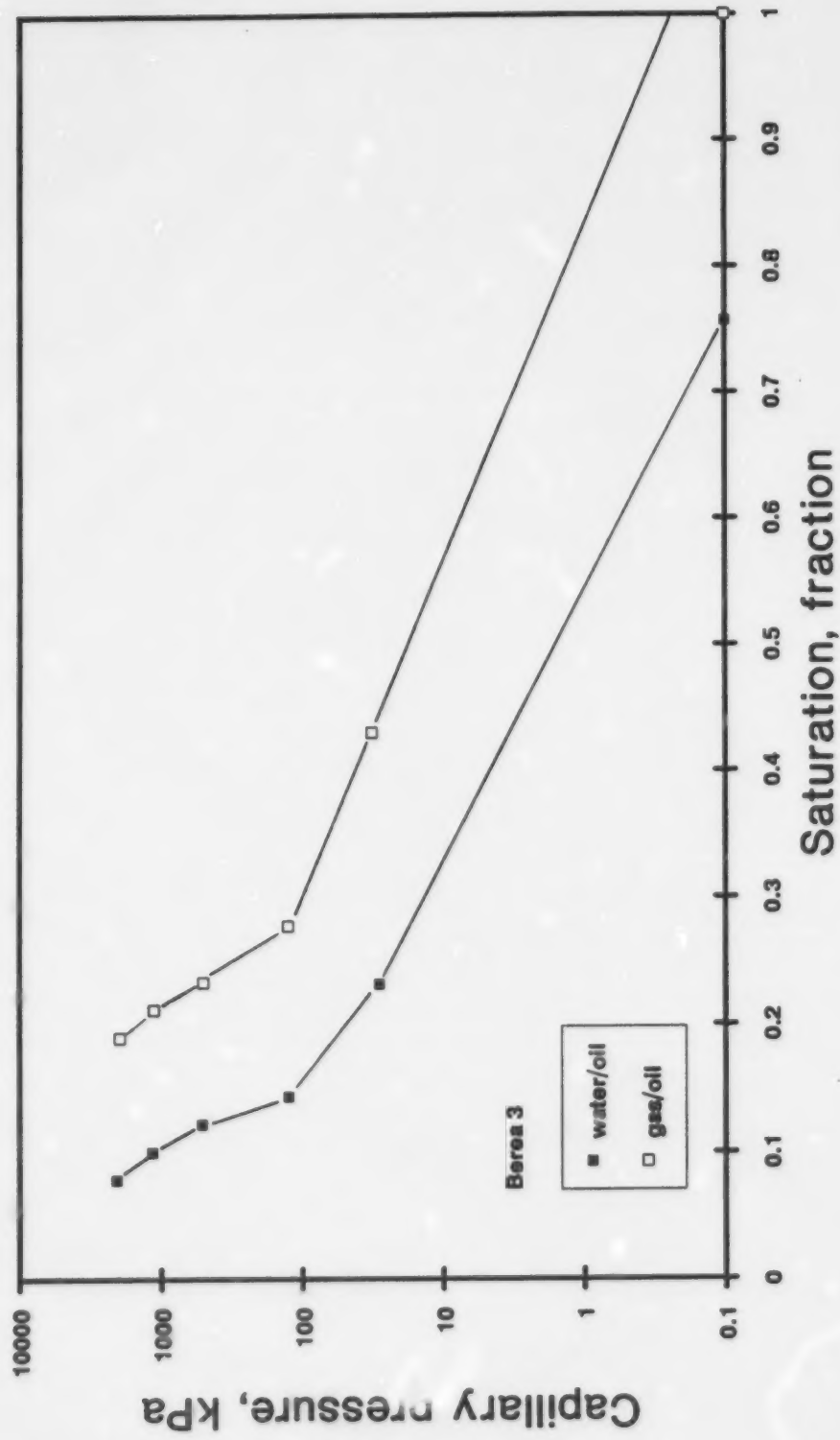


Figure 68: Proposed capillary pressure scheme for gas Injection Berea 03.

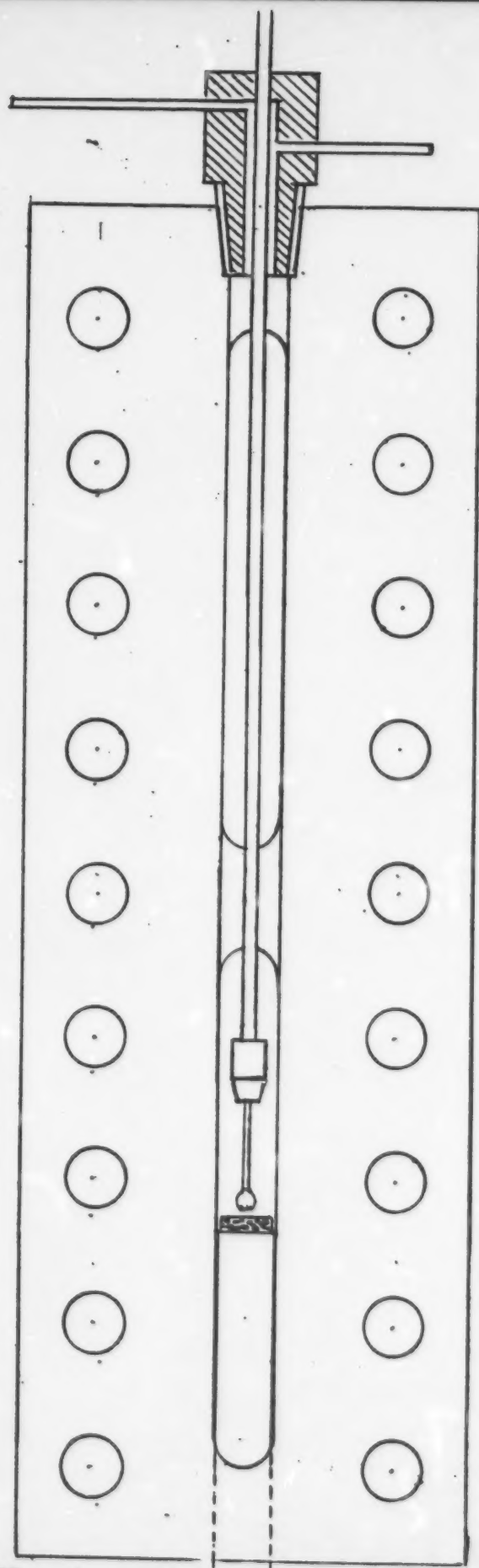


Figure 69: Contact angle measurement cell.

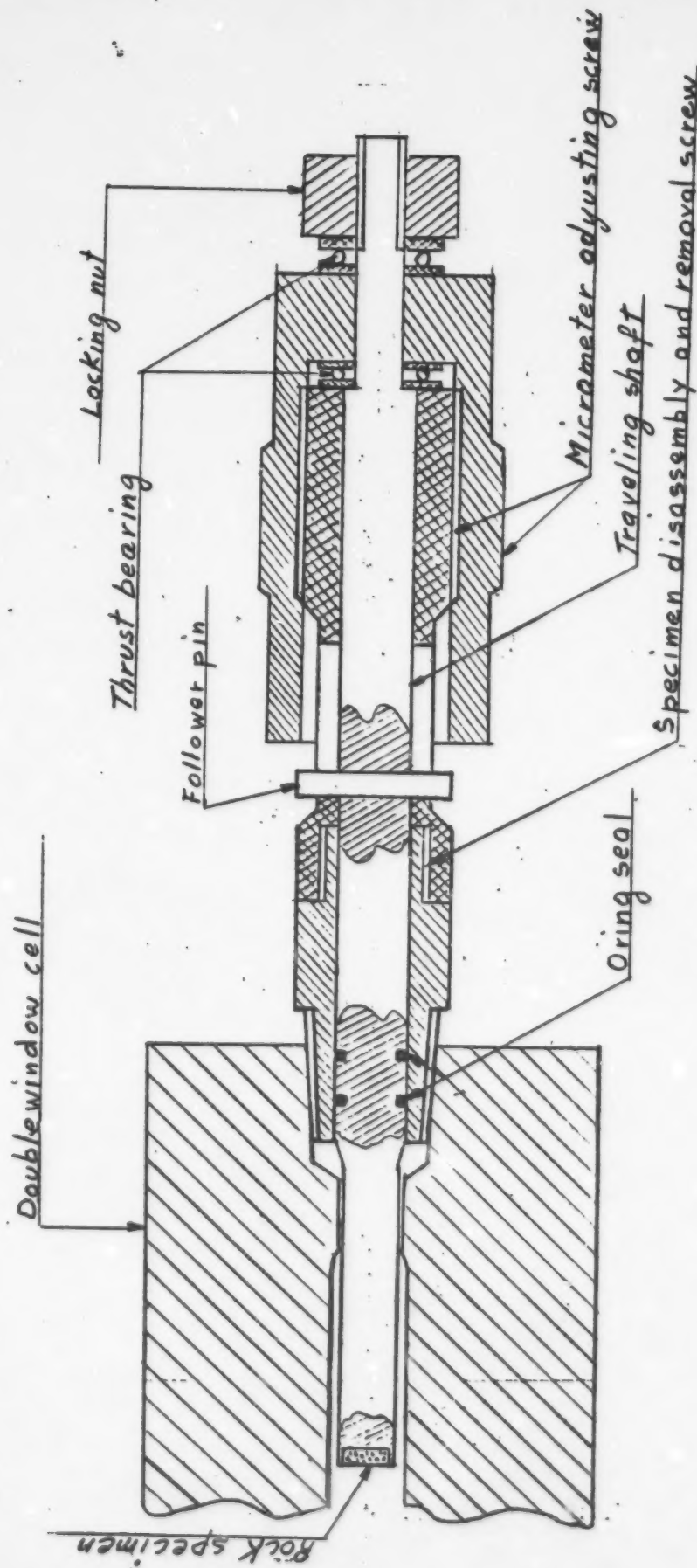
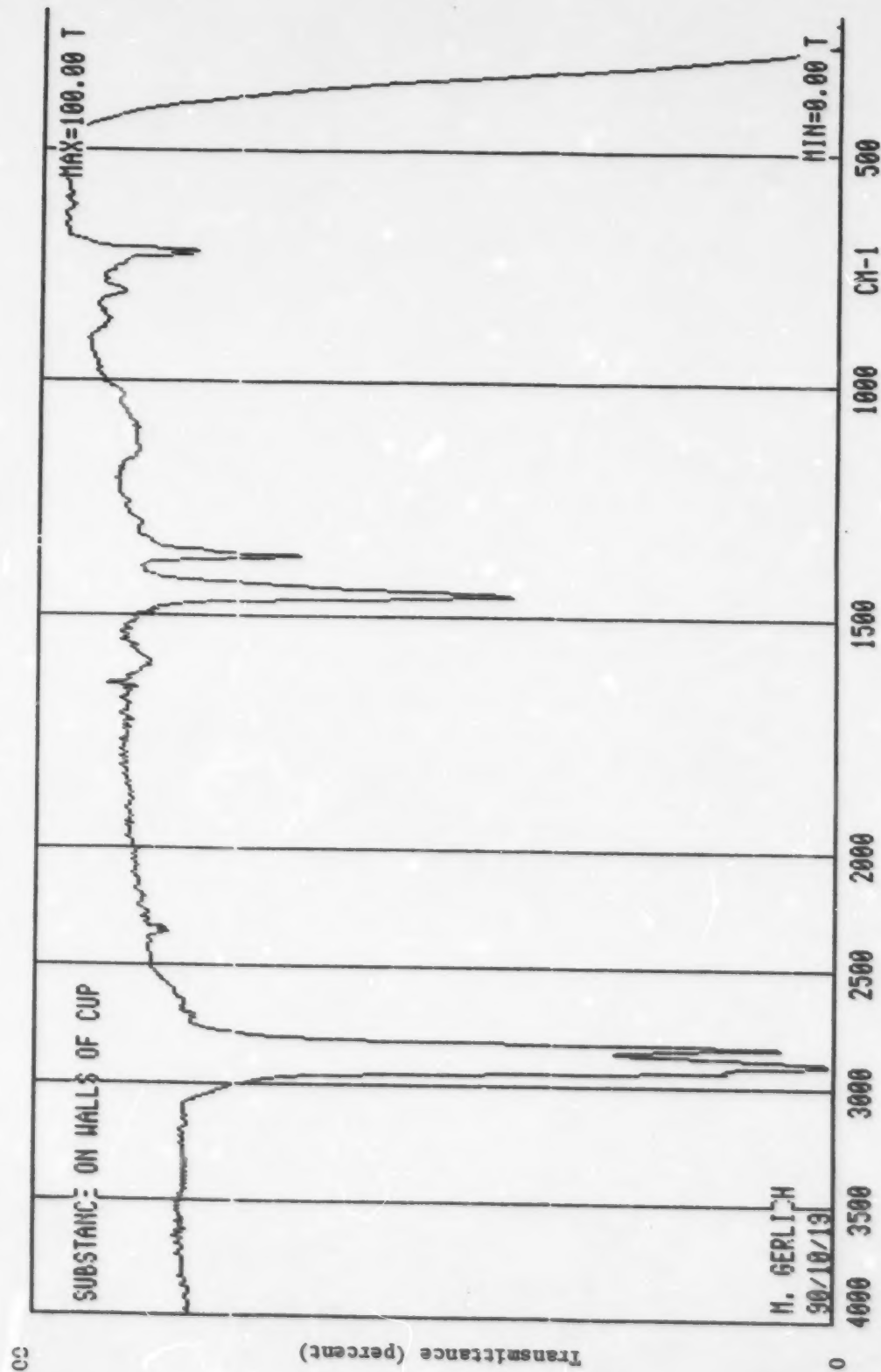


Figure 70: Contact angle sample adjusting apparatus.

Figure 71: Infra-red spectrum of substance removed from walls of cup (untreated).



Wavenumber (cm⁻¹)

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Figure 72: Infra-red spectrum of Rainbow Keg River "F" Pool oil.

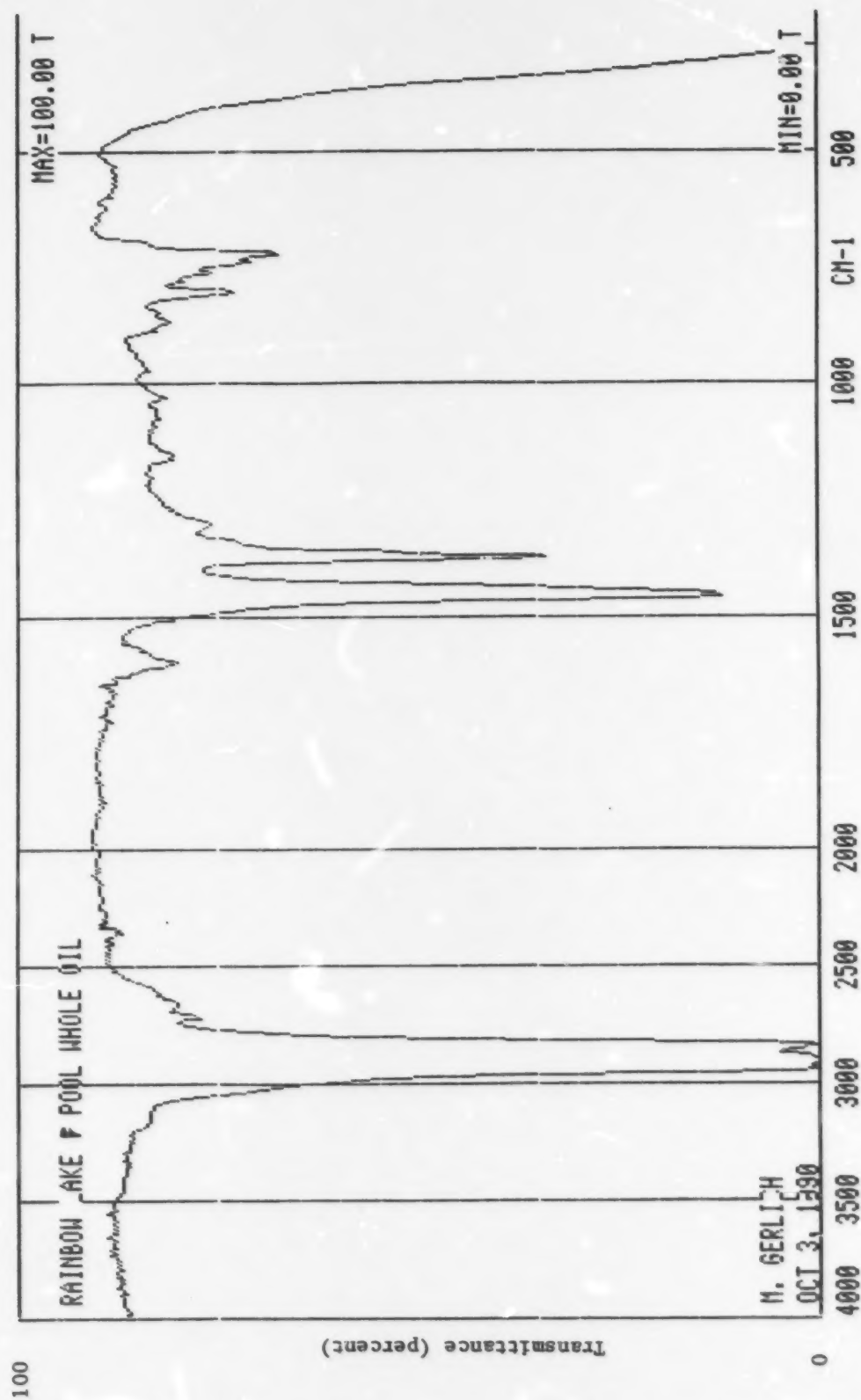


Figure 73: Infra-red spectrum of wax from RKR "F" Pool.

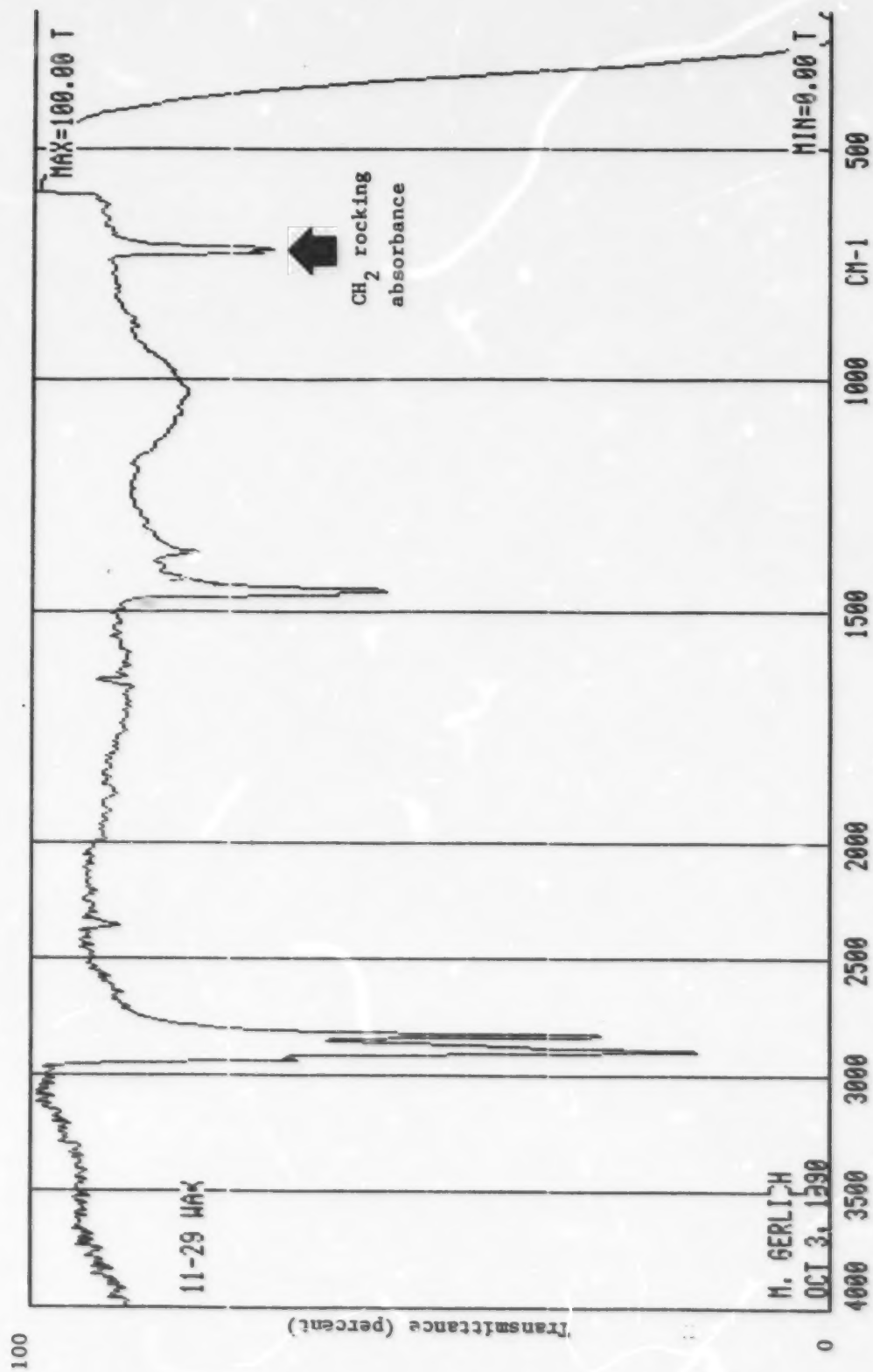


Figure 74: Scanning Electron Micrograph of washed solids on the surface of filter for RKR "F" Pool of
(5000X MAGNIFICATION)



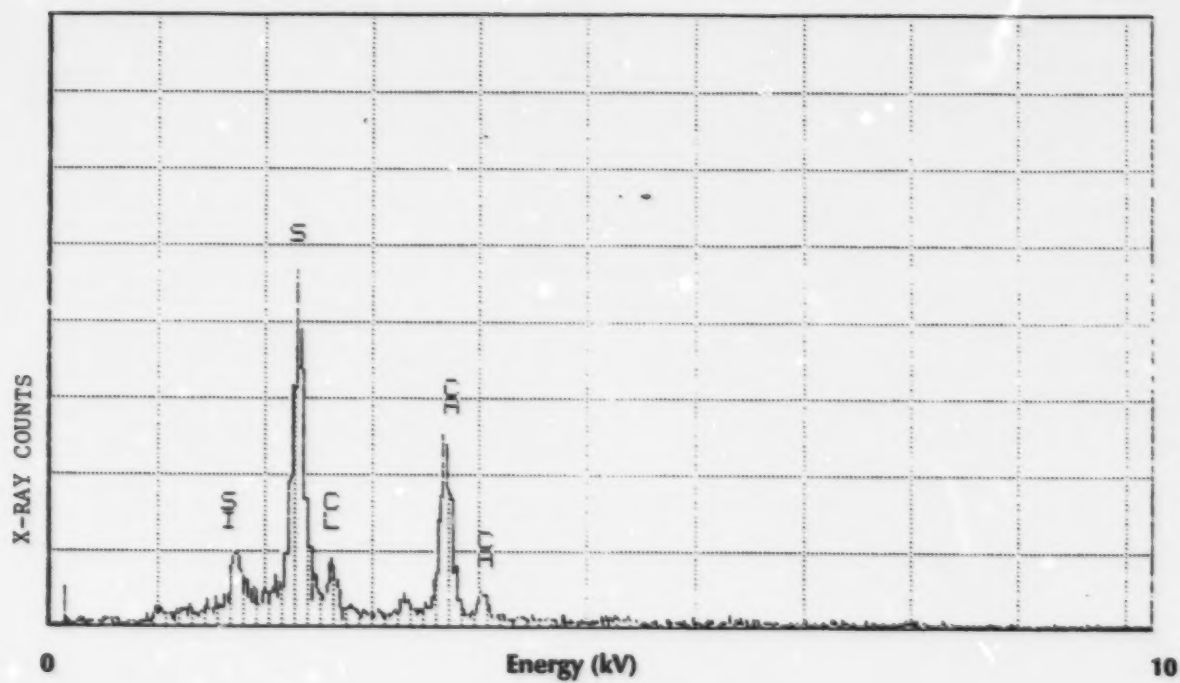


Figure 75: EDX spectrum of washed solids from RKR "F" Pool oil.

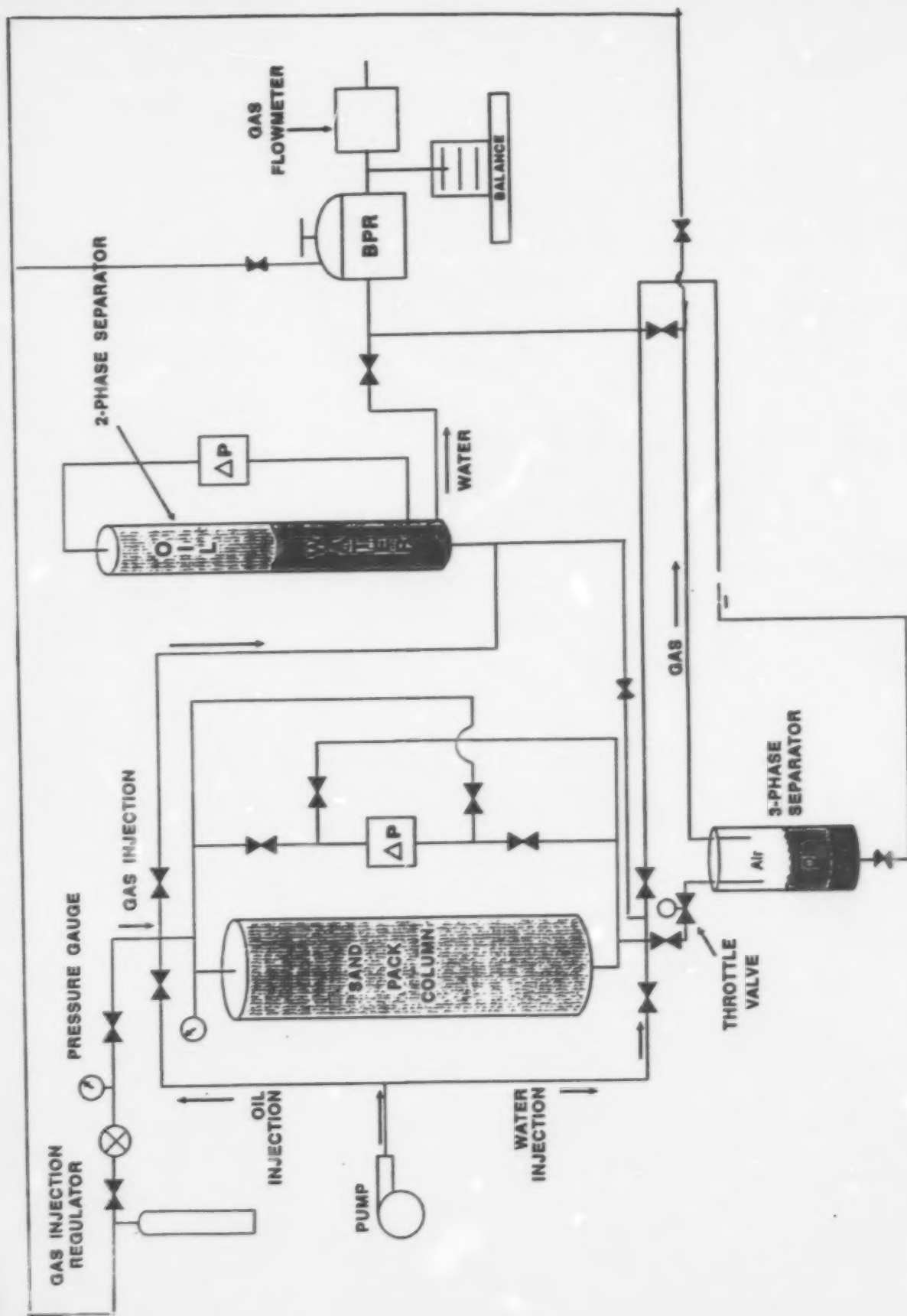


Figure 76: Schematic diagram of the Gravity Assisted Immiscible Gas Injection Apparatus.

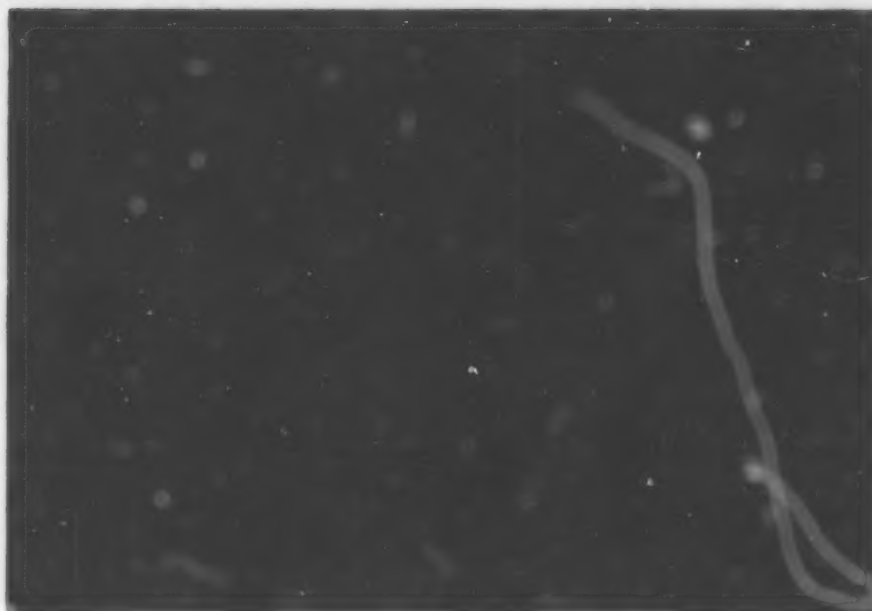


Figure 77: Photograph of the short ambient columns saturated with brine.

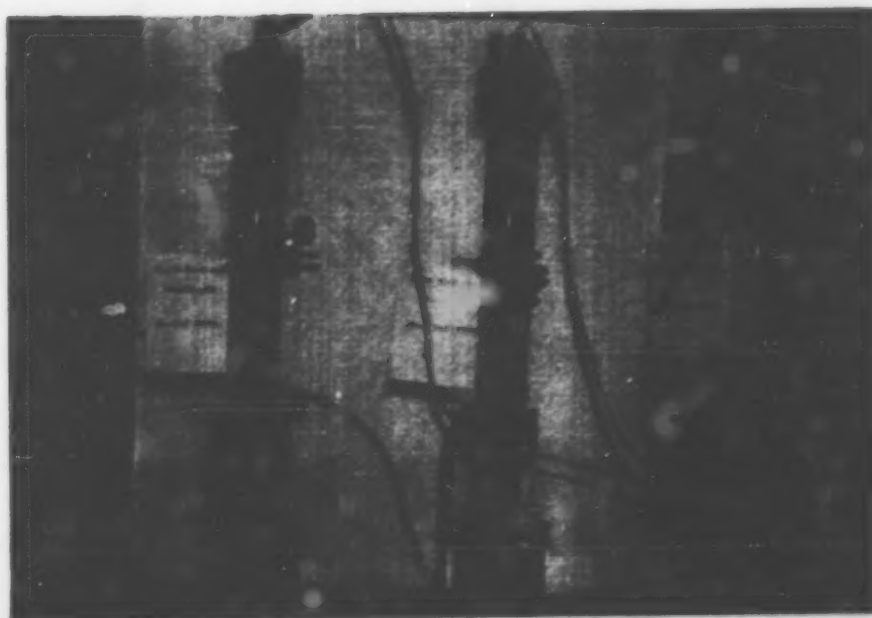


Figure 78: Photograph of the short ambient columns at beginning of oil floods.

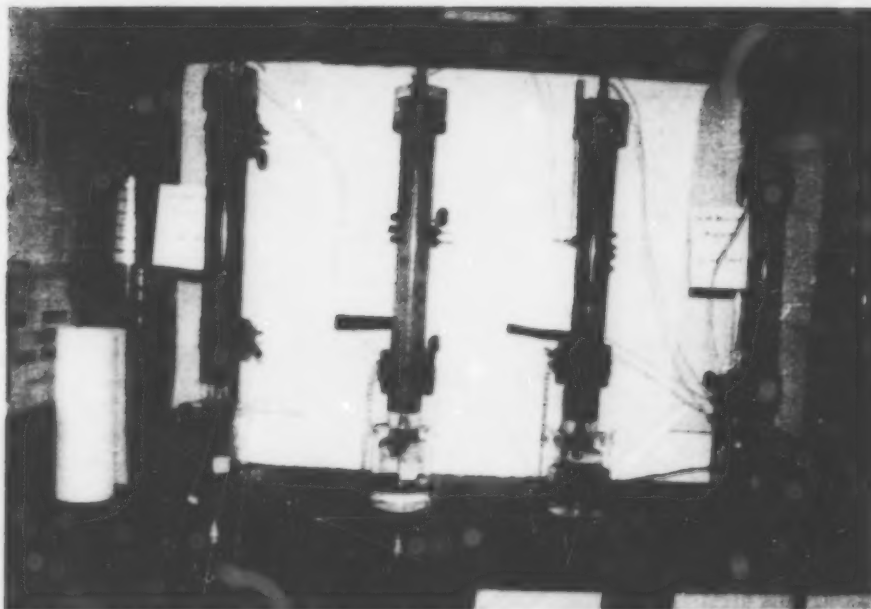


Figure 79: Photograph of the short ambient columns at the beginning of gas flood.

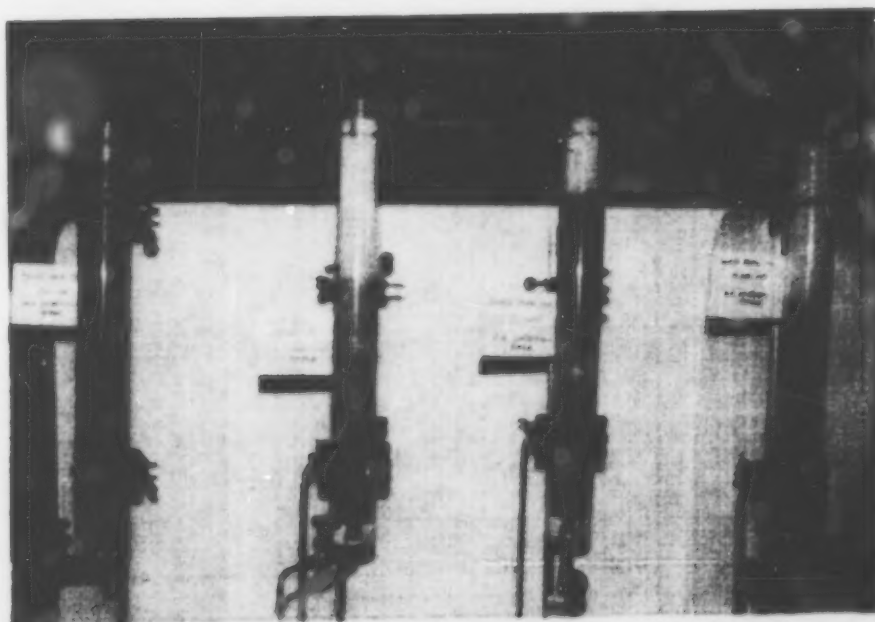


Figure 80: Photograph of the short ambient columns after gas injection started.

Oil banks are shown in the oil wet and mixed wet glass bead columns.

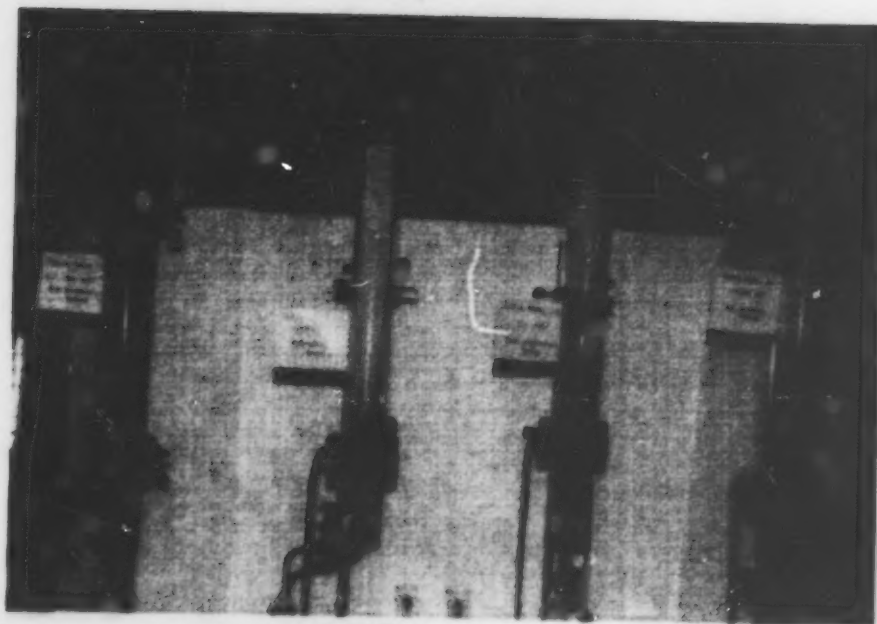


Figure 81: Photograph of the short ambient columns during gas injection. Visualization of the oil propagation of the oil bank.



Figure 82: Photograph of the oil bank propagation during gas injection in short ambient columns.

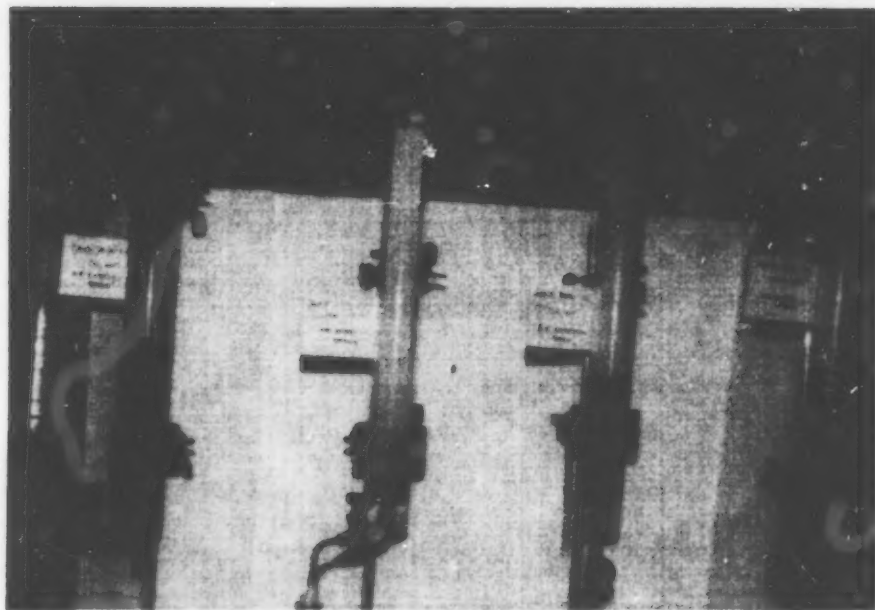


Figure 83: Photograph of gas injection in short ambient columns.
Oil bank reaches the production end.

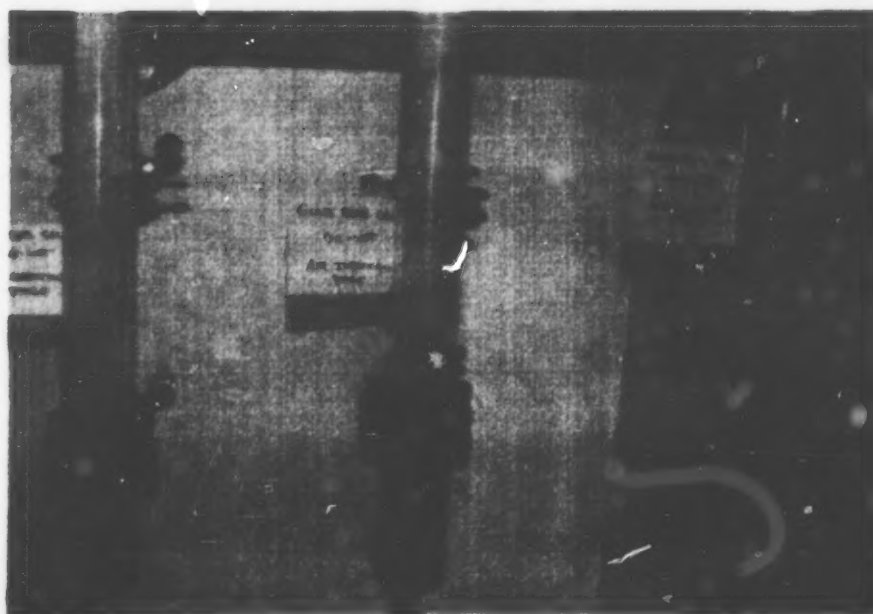


Figure 84: Photograph of the production end of the glass bead columns. Oil is produced.

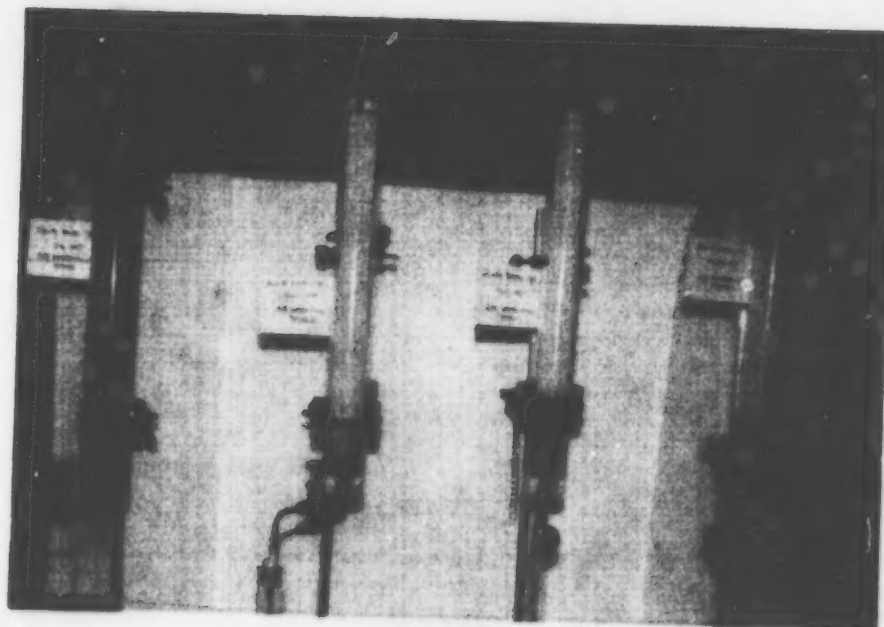


Figure 85: Production of the oil bank in the glass bead columns.

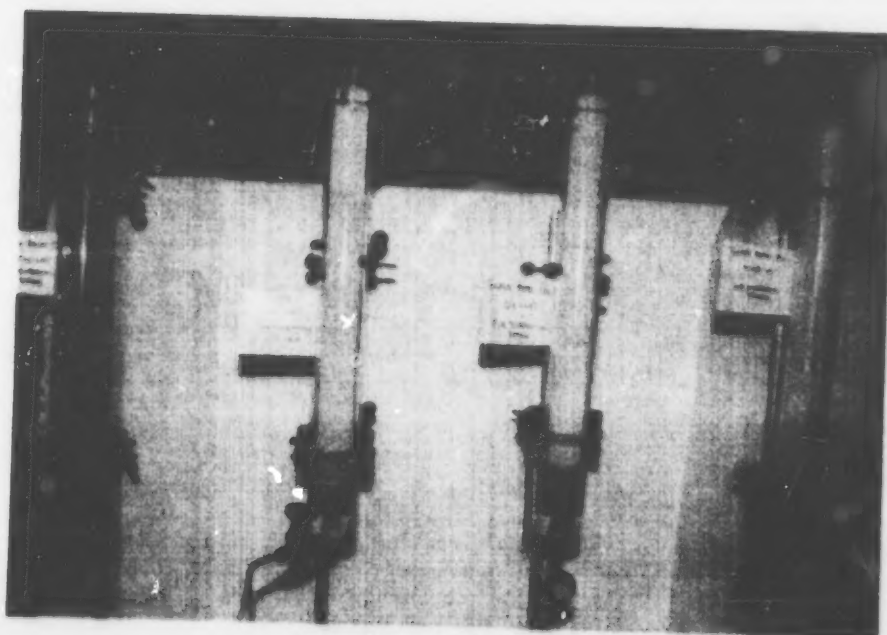


Figure 86: Production of the oil bank in the glass bead columns.

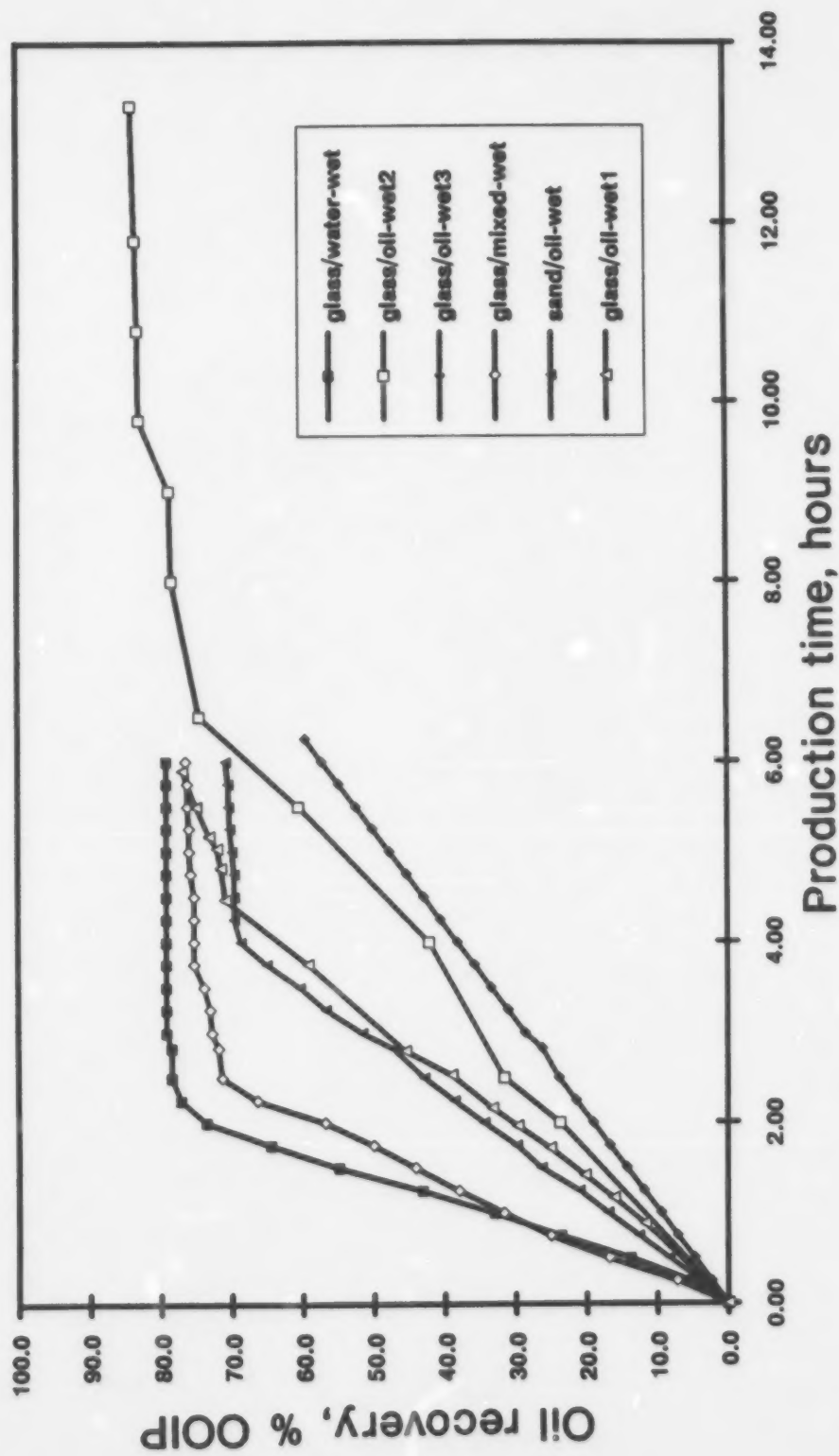


Figure 87: Waterflood recovery from the various columns.

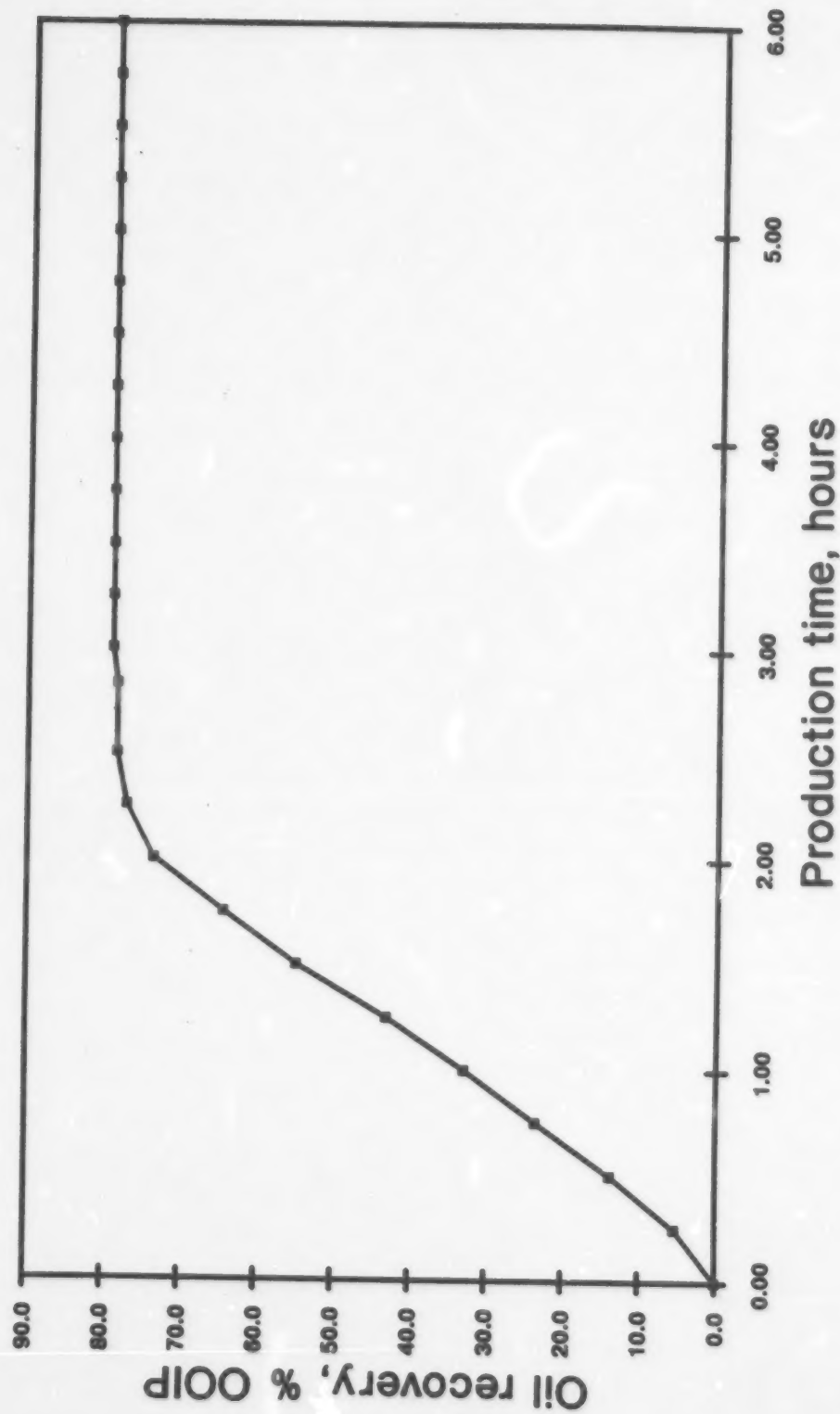


Figure 88: Waterflood recovery of water-wet glass bead column.

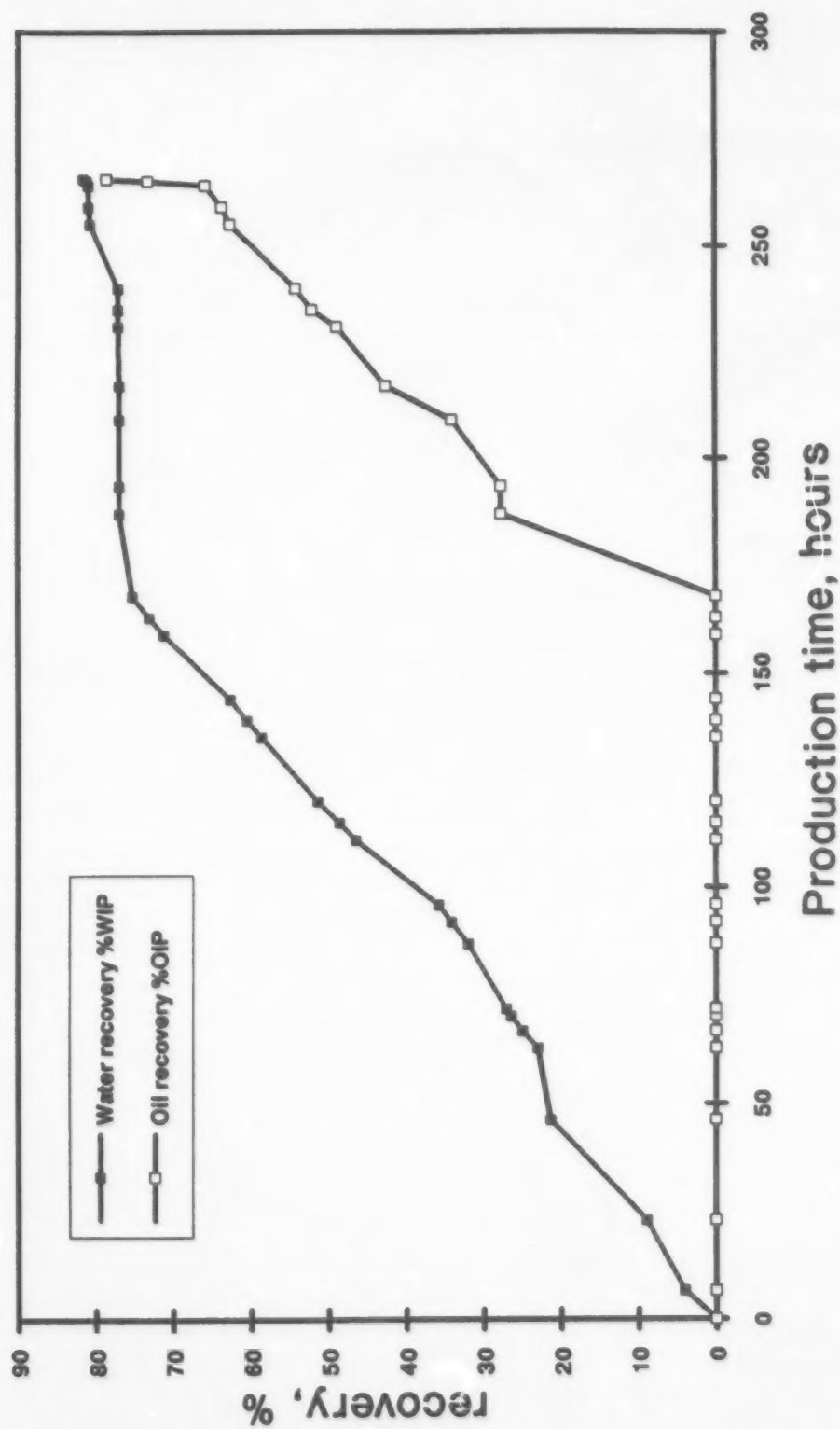


Figure 89: Liquid production during gas injection of water wet glass bead column.

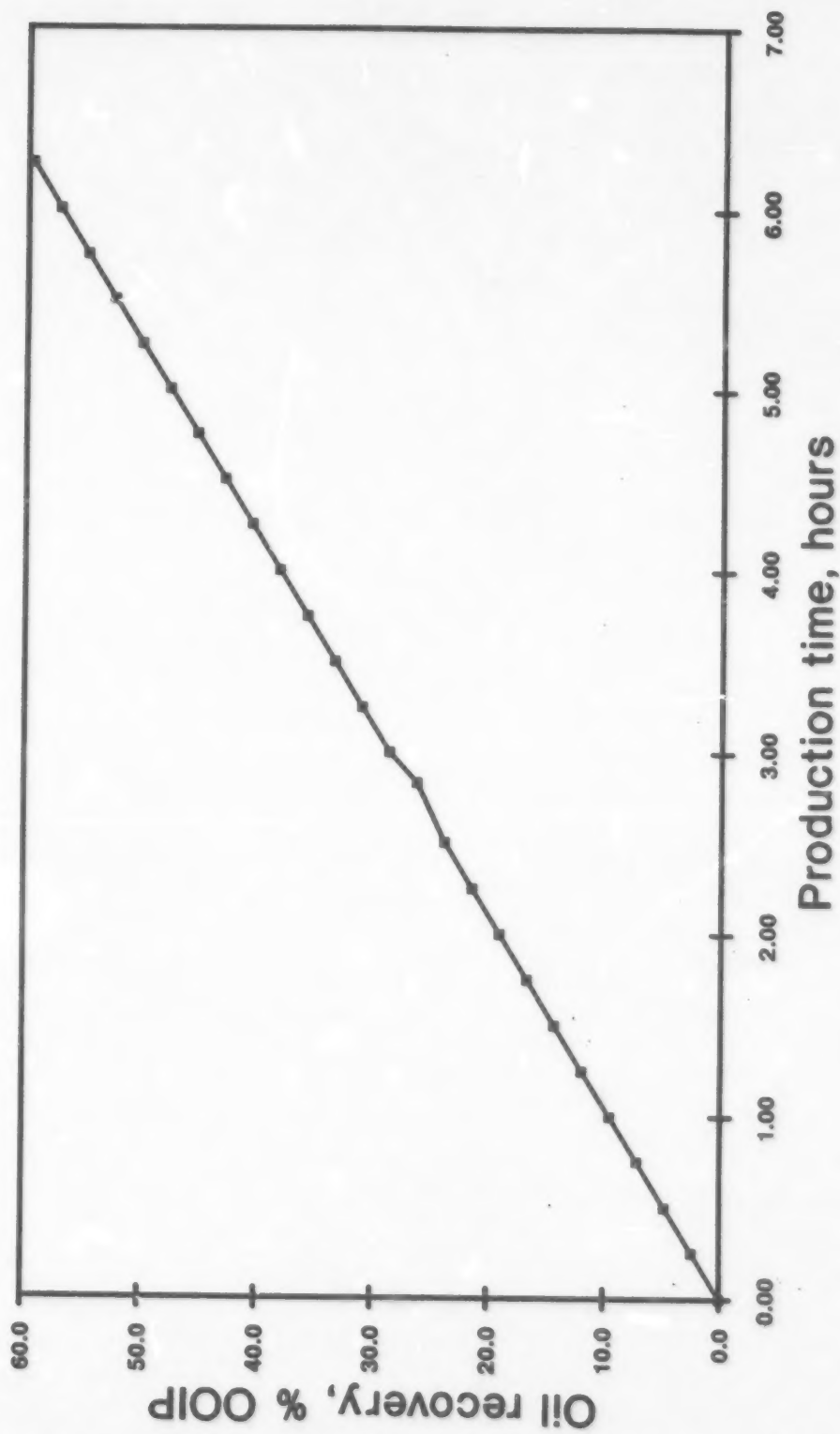


Figure 90: Waterflood recovery of oil wet glass bead column.

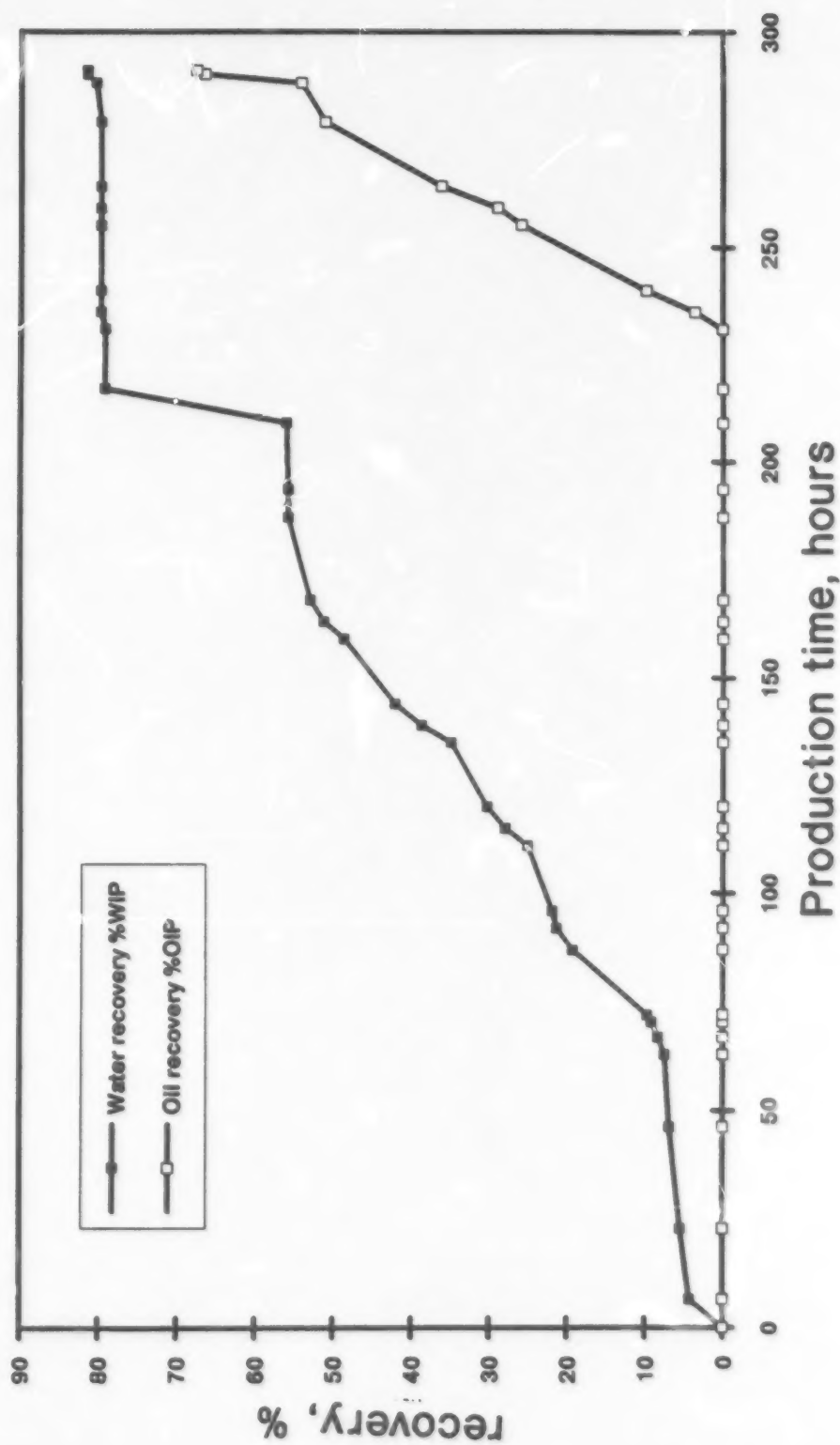


Figure 91: Liquid production during gas injection of oil wet glass bead column.

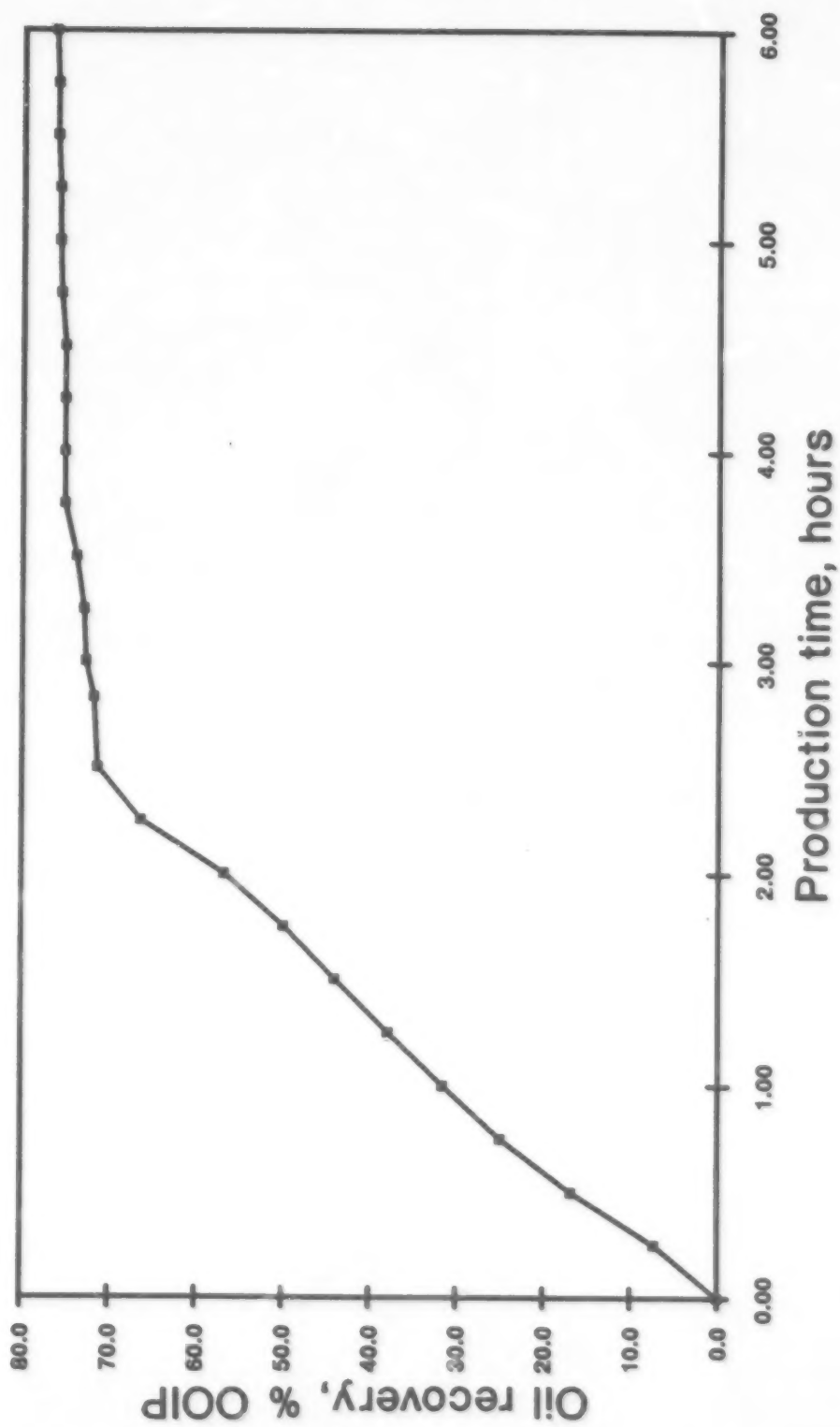


Figure 92: Waterflood recovery of mixed wet glass bead column.

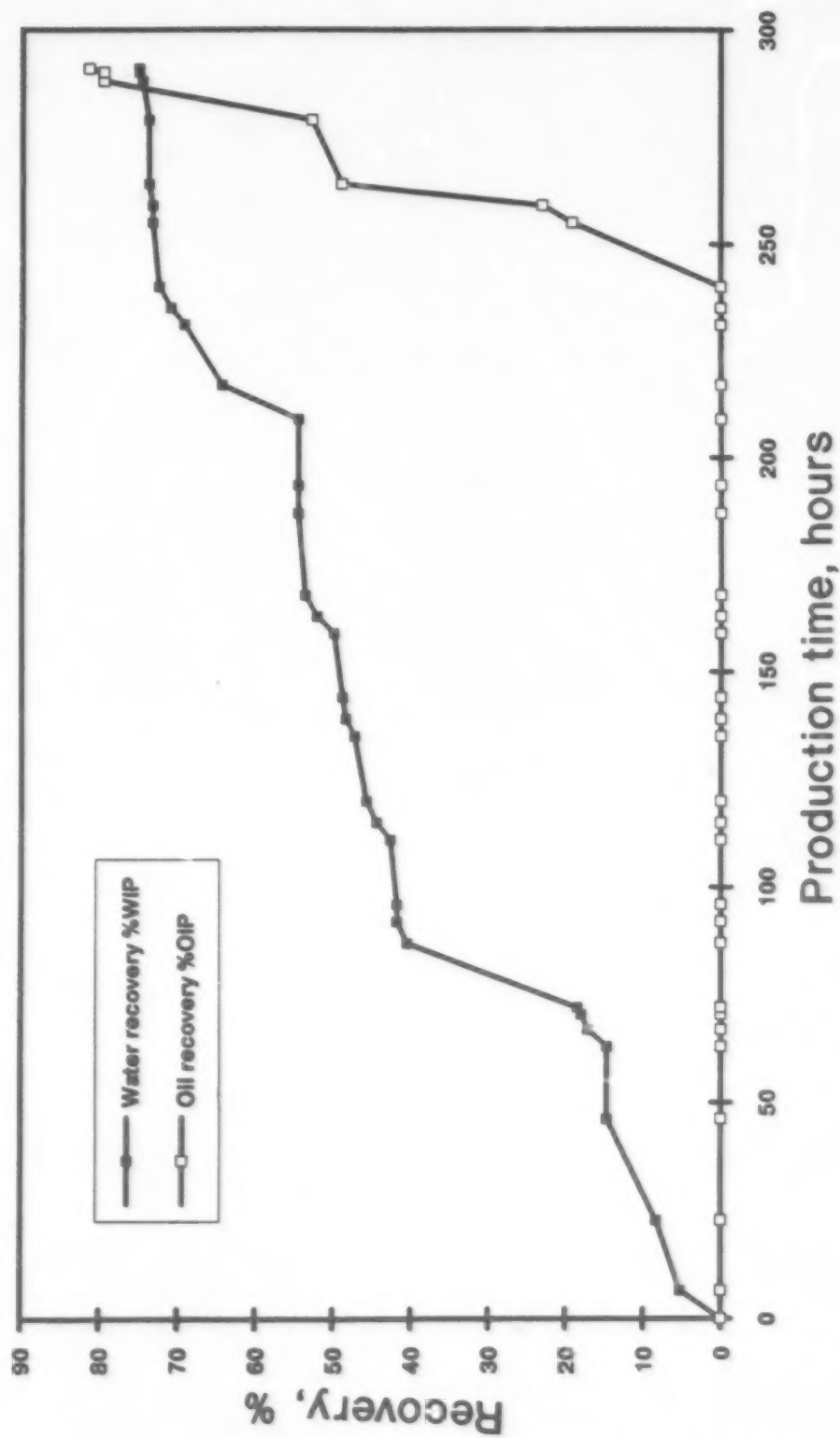


Figure 93: Liquid production during gas injection of mixed wet glass bead column.

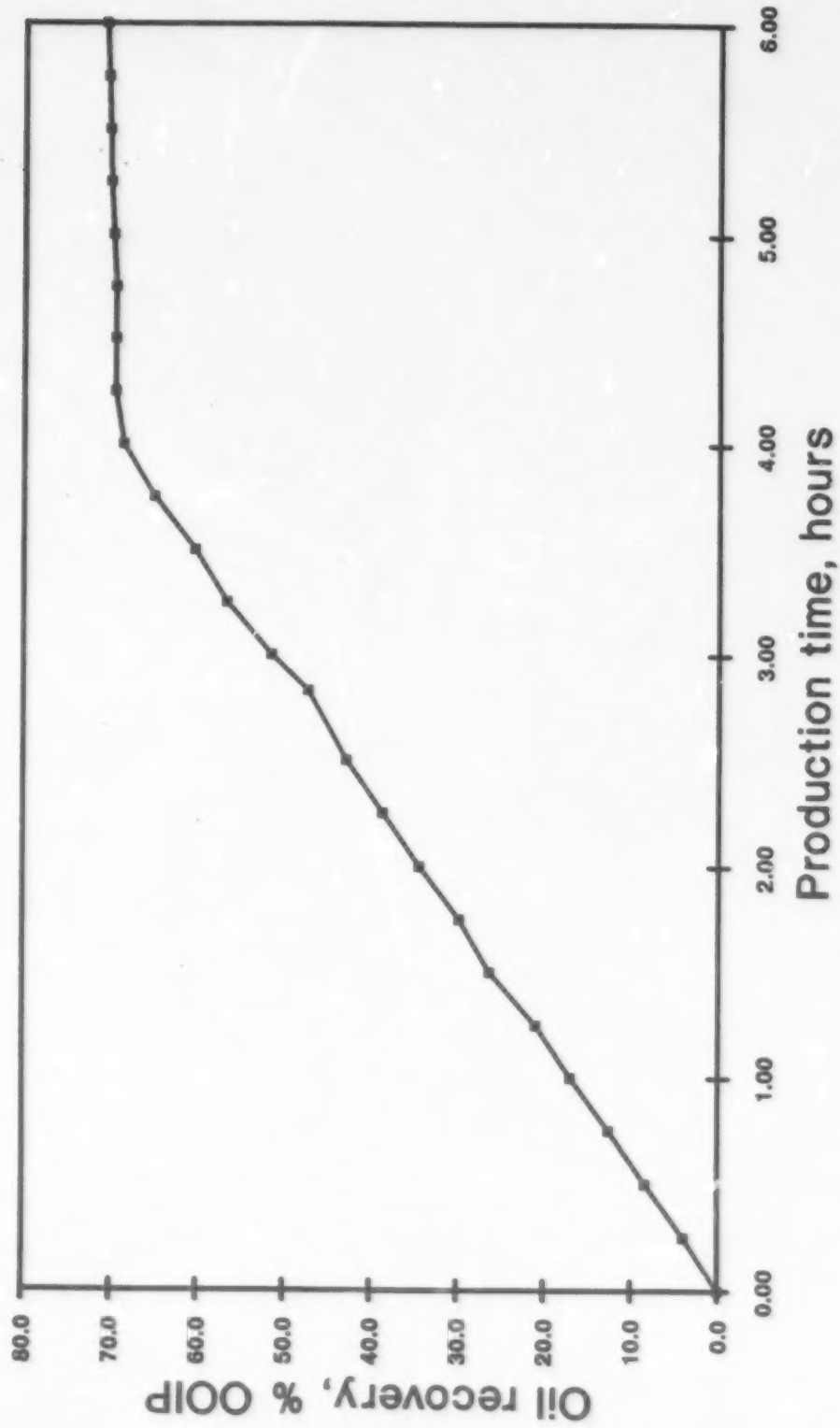


Figure 94: Waterflood recovery of oil wet sand pack column.

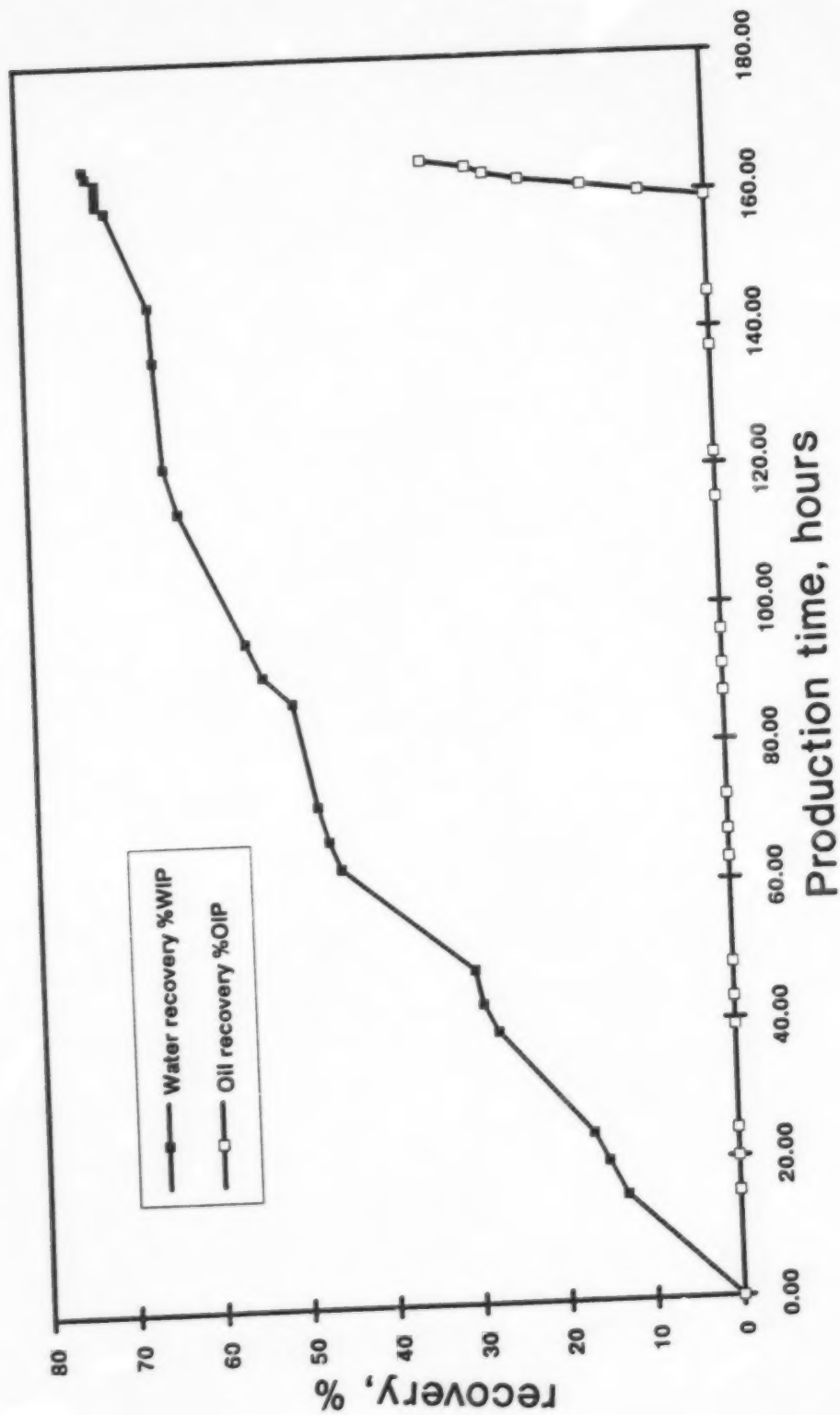


Figure 95: Liquid production during gas injection of oil wet sand pack column.



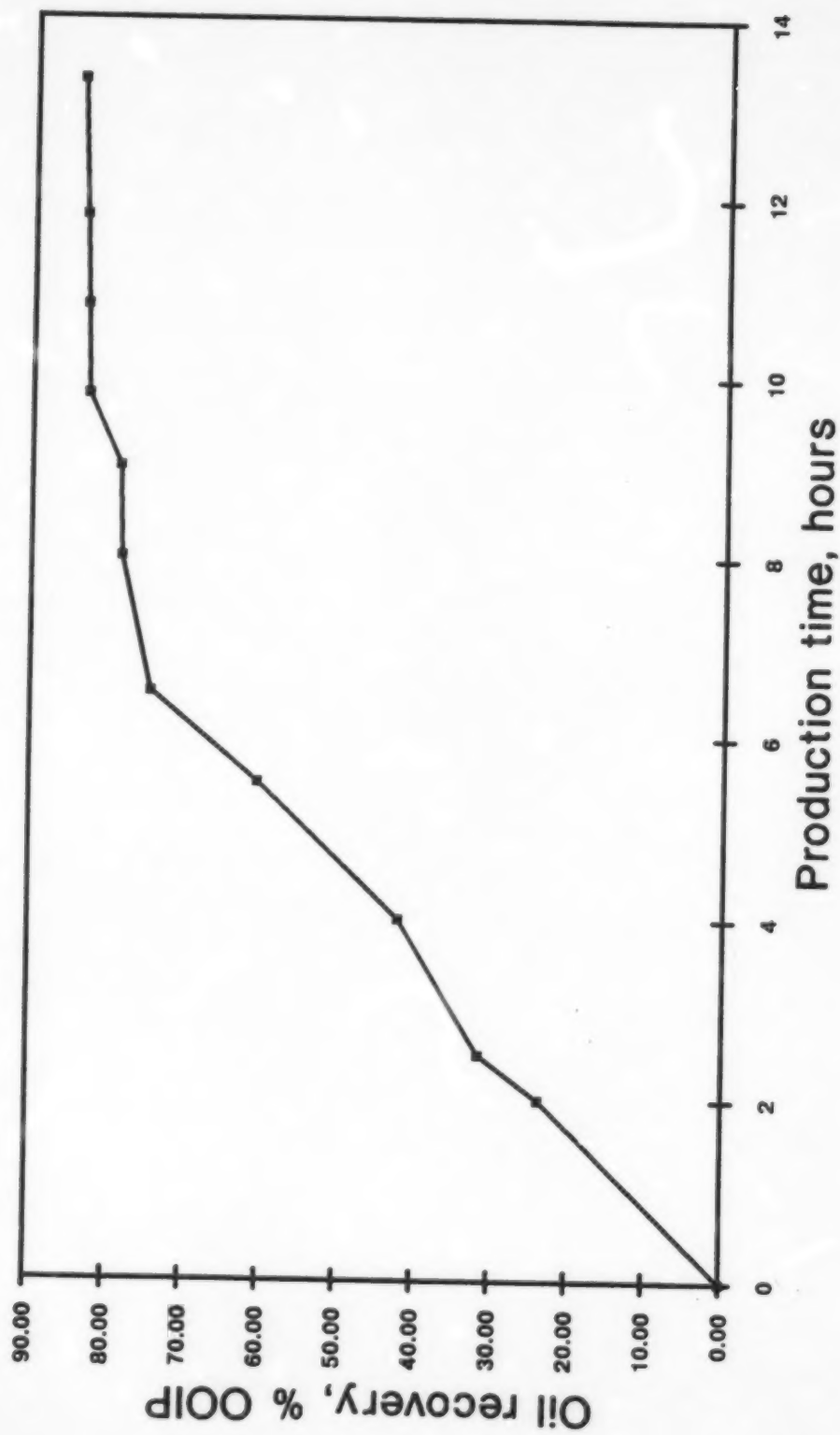


Figure 96: Waterflood recovery of second oil wet glass bead column.

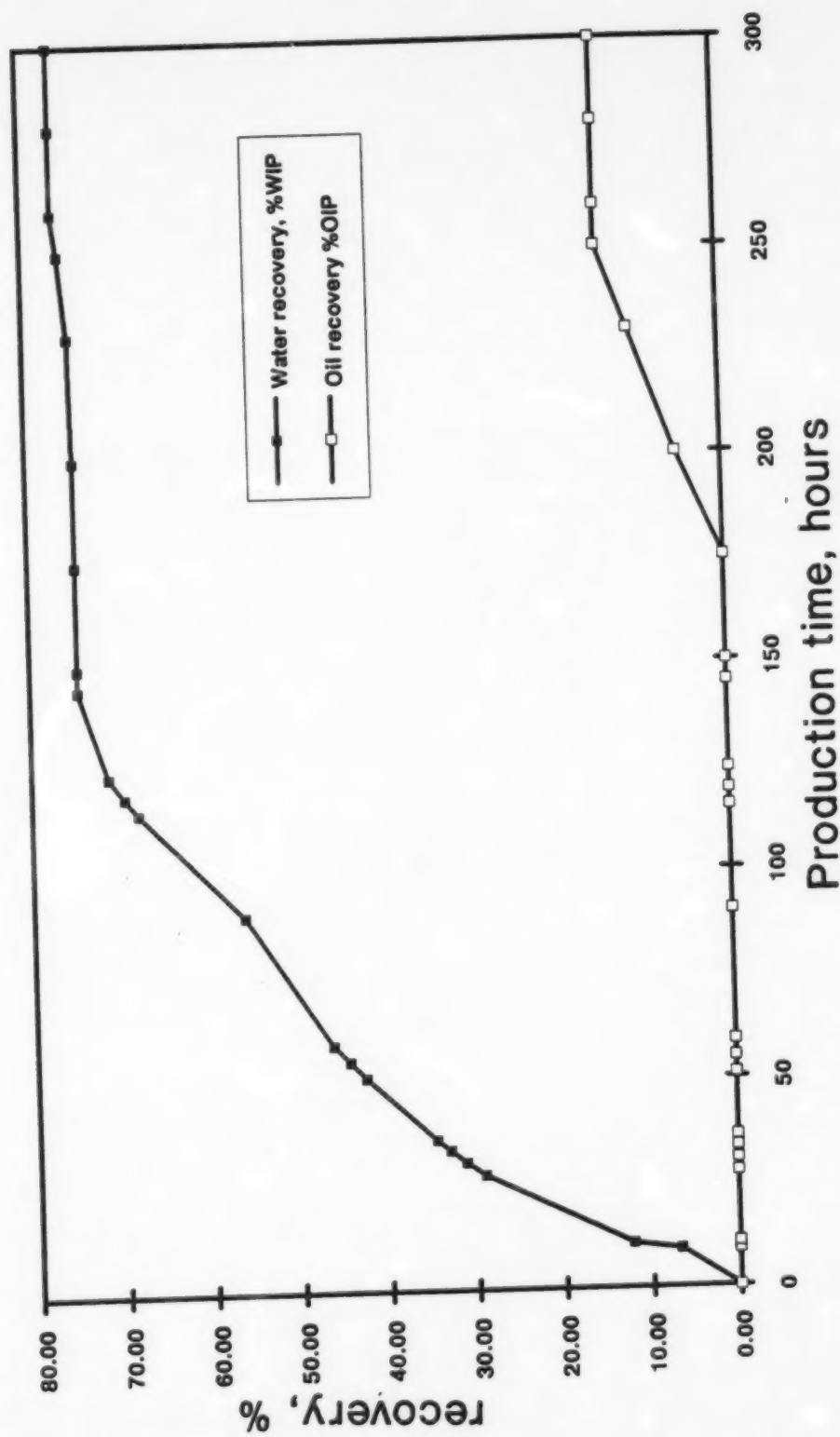


Figure 97: Liquid production during gas injection of second oil wet glass bead column.

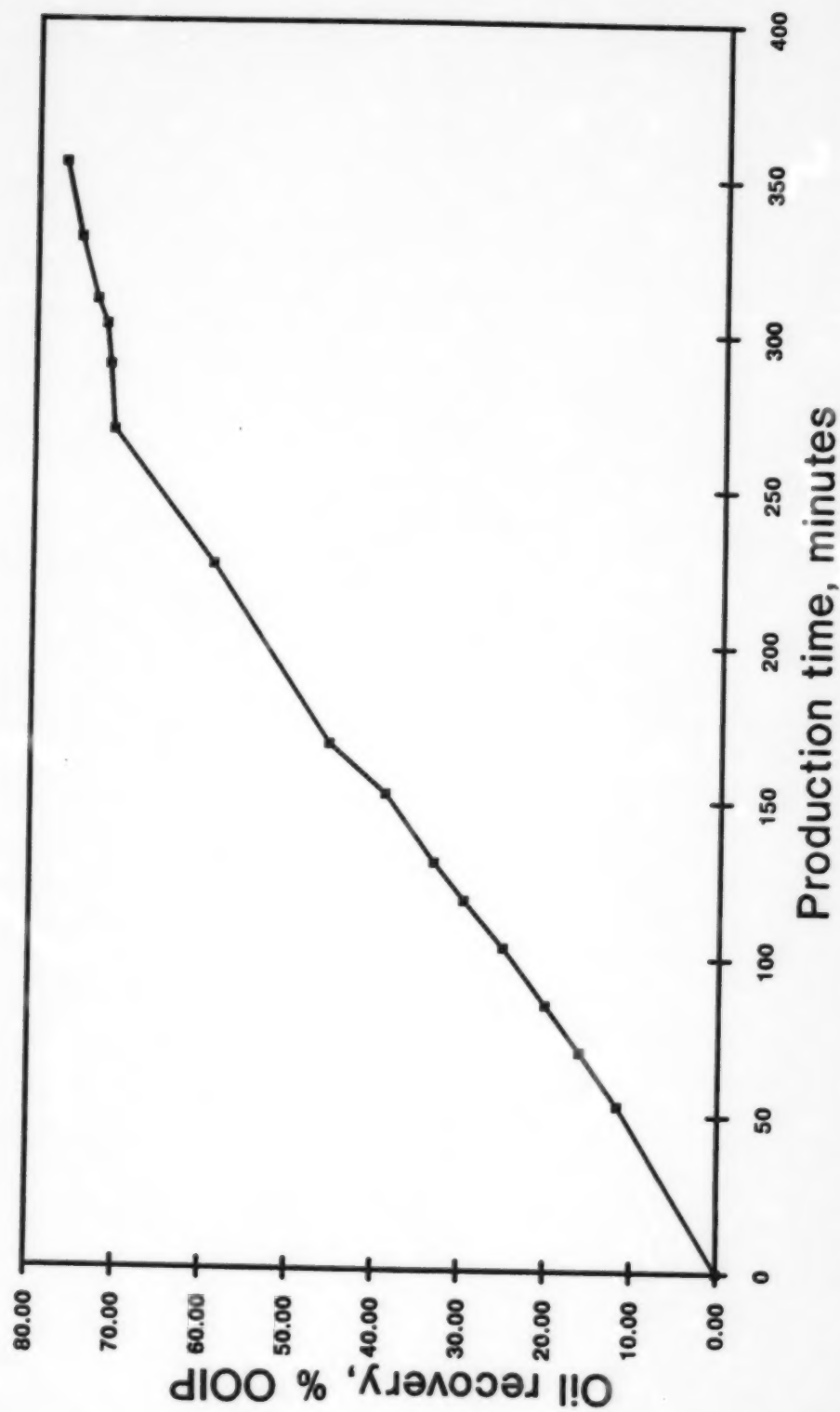


Figure 98: Waterflood recovery of third oil wet glass bead column.

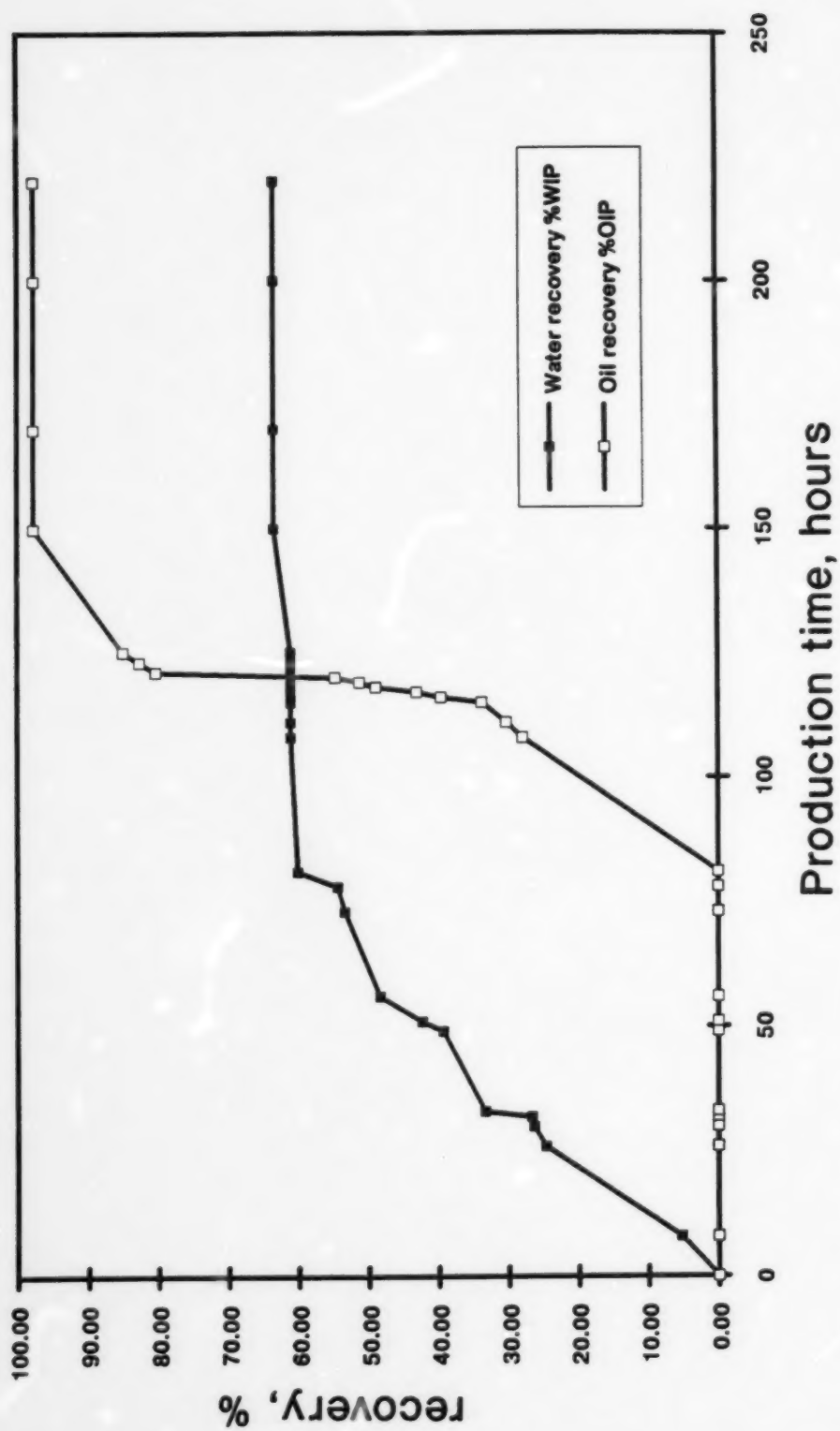


Figure 99: Liquid production during gas injection of third oil wet glass bead column.

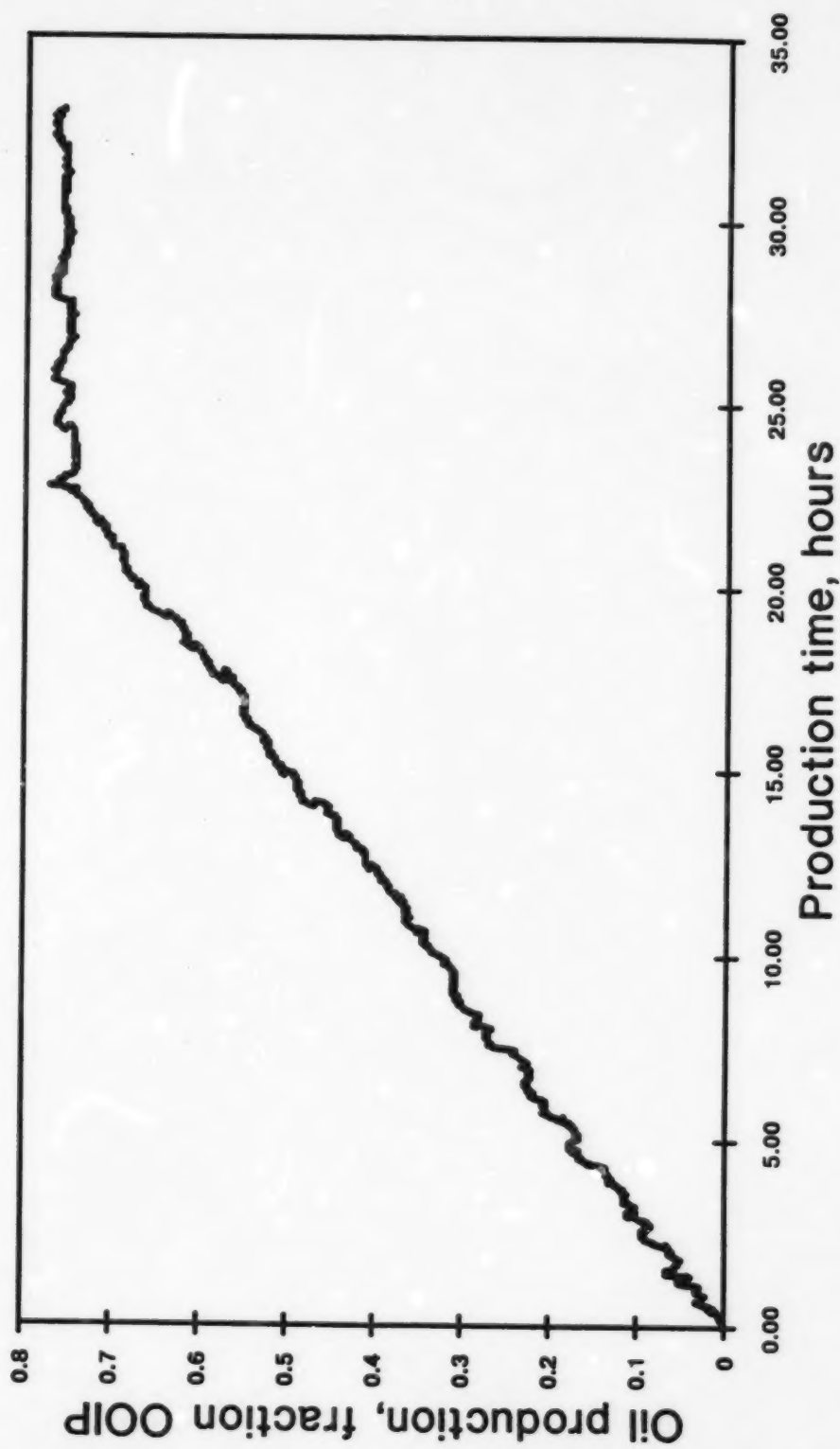


Figure 100: Waterflood recovery of long water wet sand pack column.

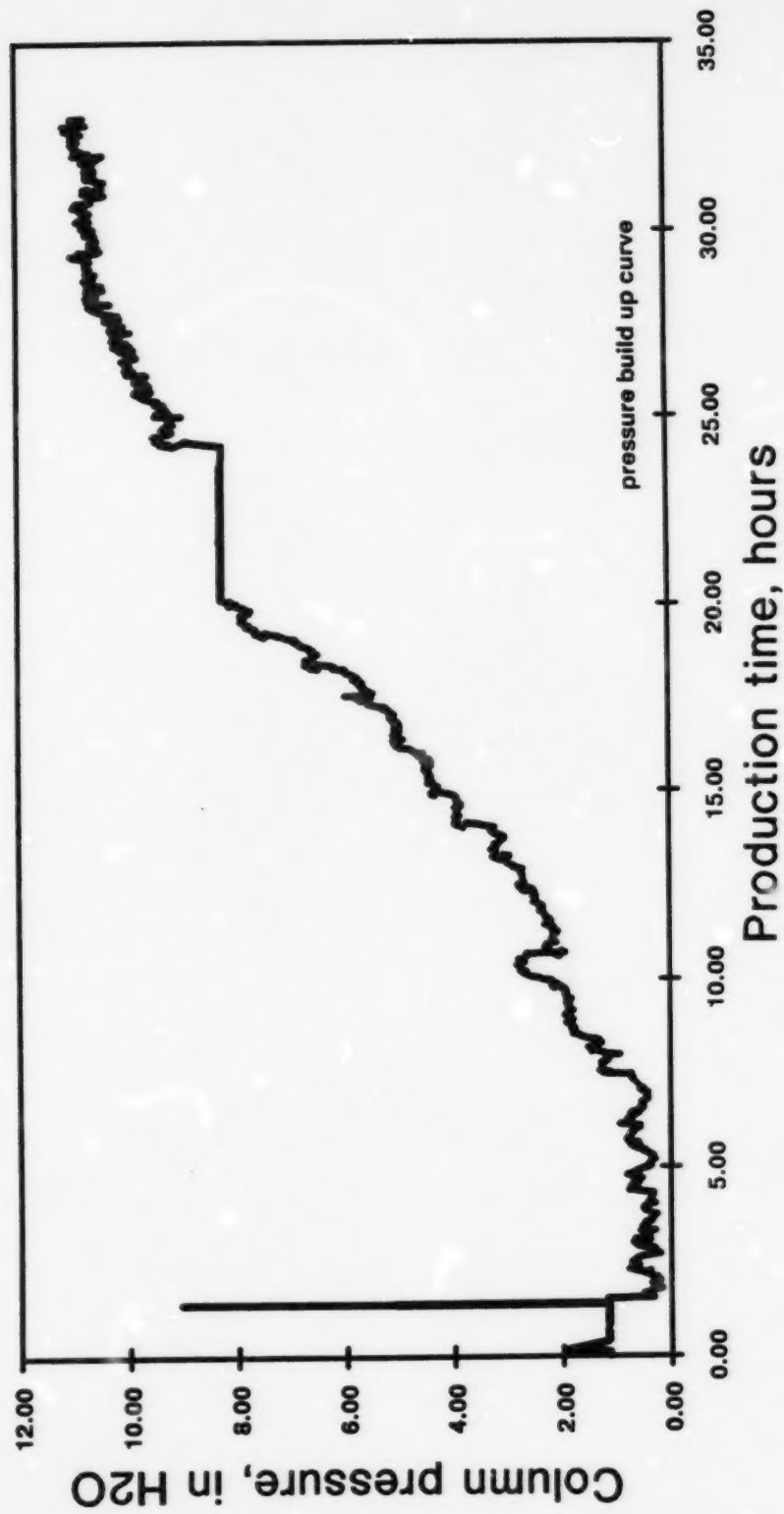


Figure 101: Pressure build up in long water wet sand pack column during waterflood.

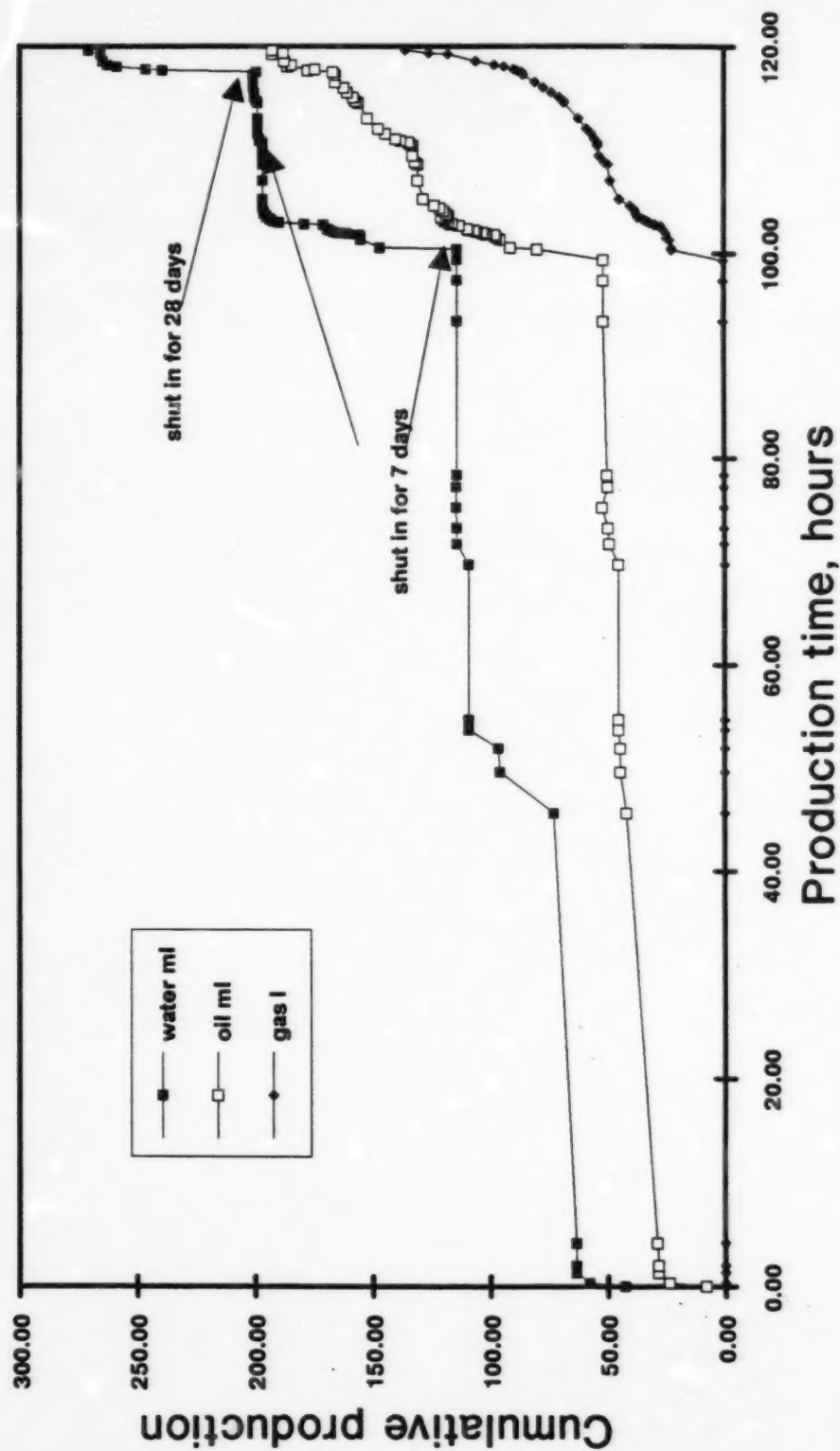


Figure 102: Fluid production during gas injection of long water wet sand pack column.

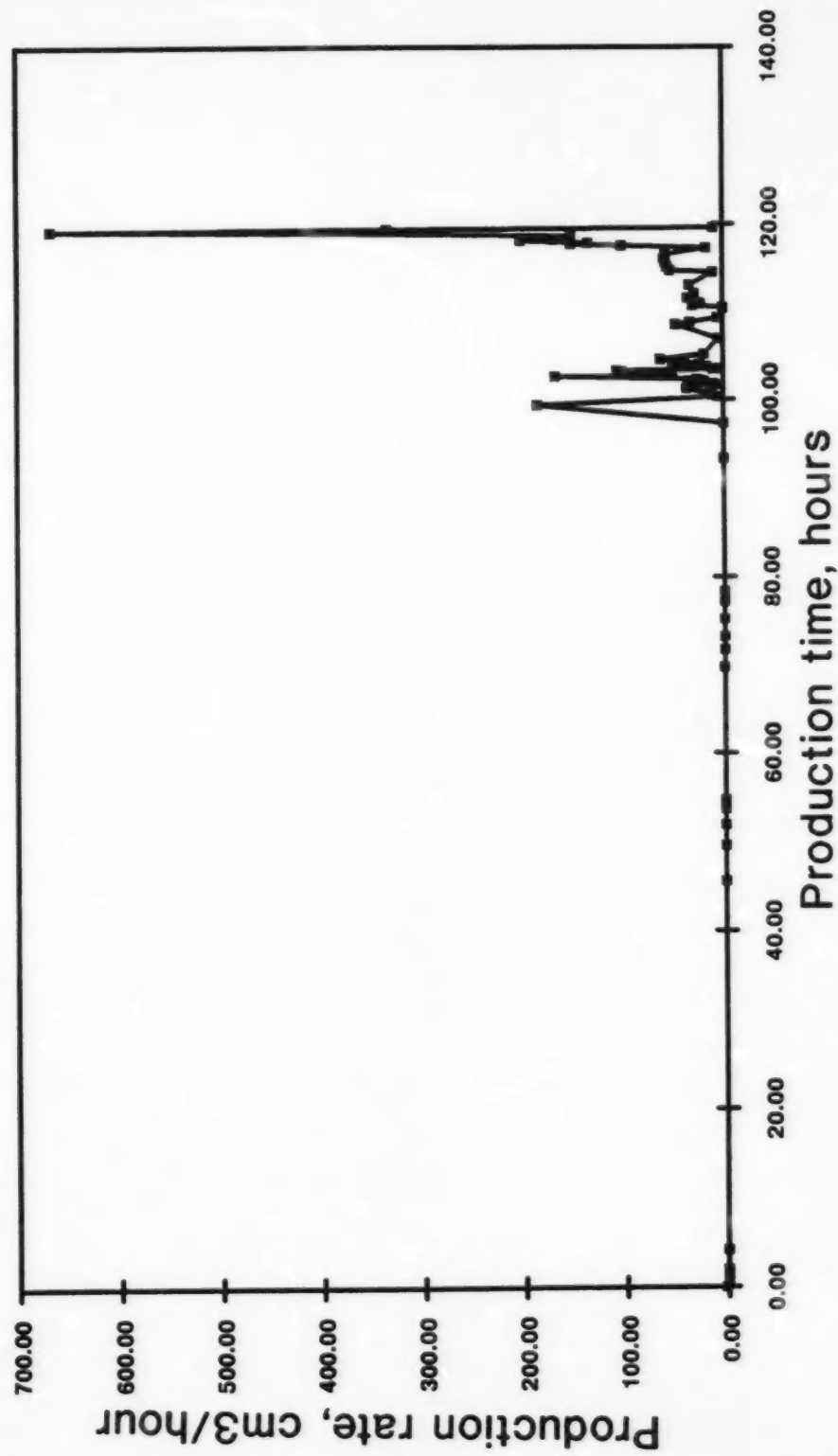


Figure 103: Oil production rate during gas injection of long water wet sand pack column.

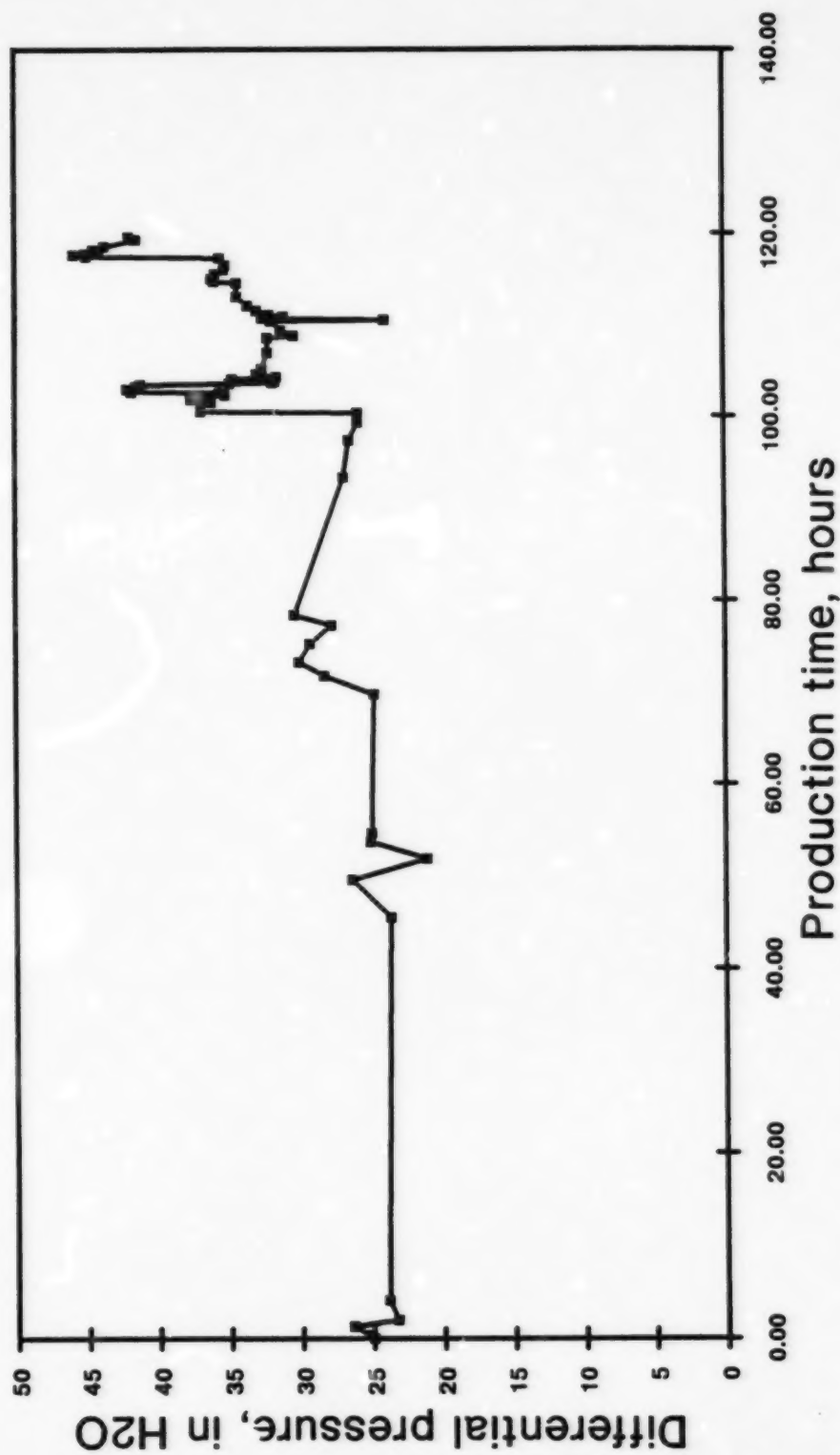


Figure 104: Pressure history profile during gas injection of long water wet sand pack column.

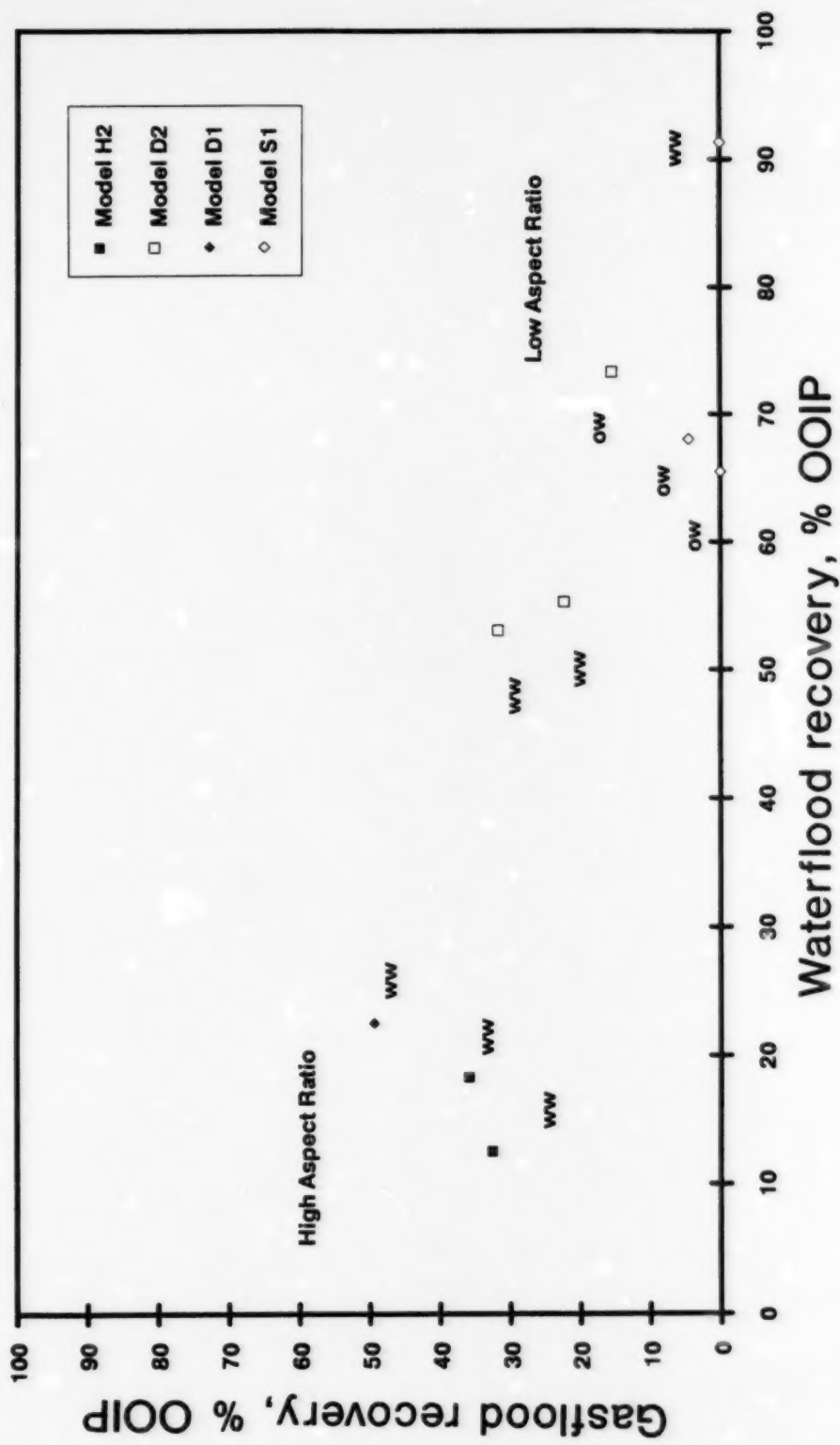


Figure 105: Gasflood recovery as a function of waterflood recovery for the micromodel tests.

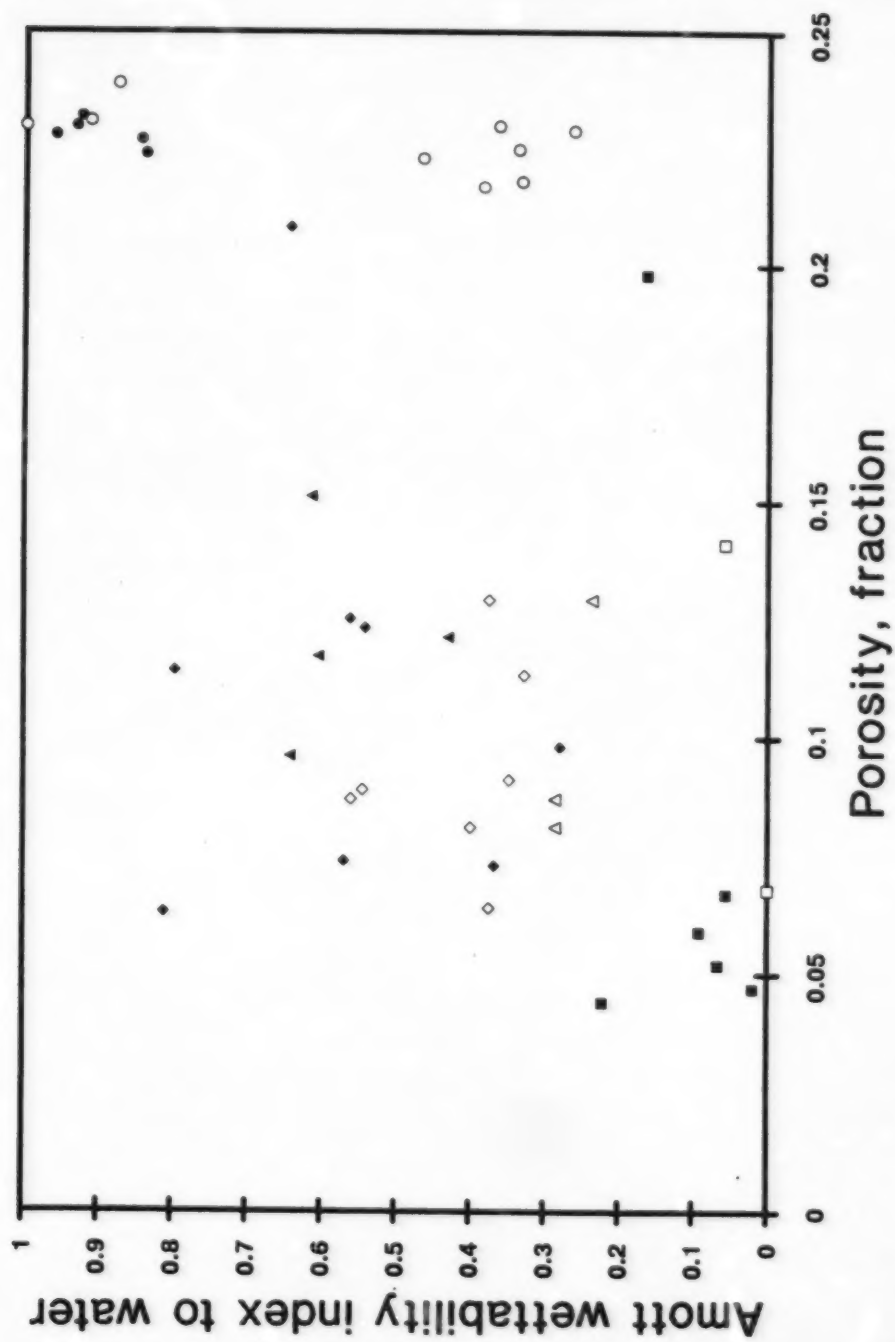


Figure 106: Amott wettability index to water as a function of porosity.

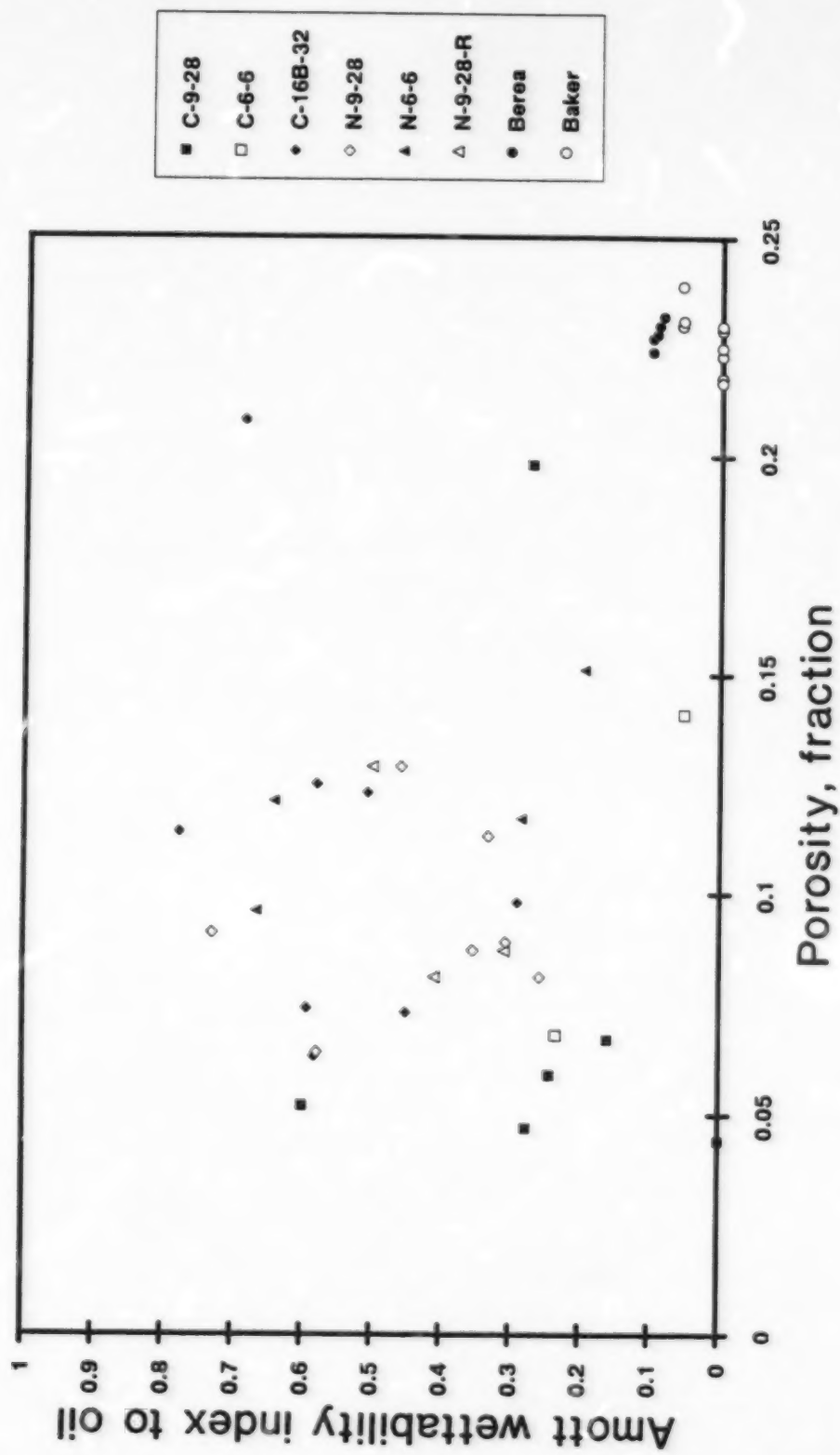


Figure 107: Amott wettability index to oil as a function of porosity.

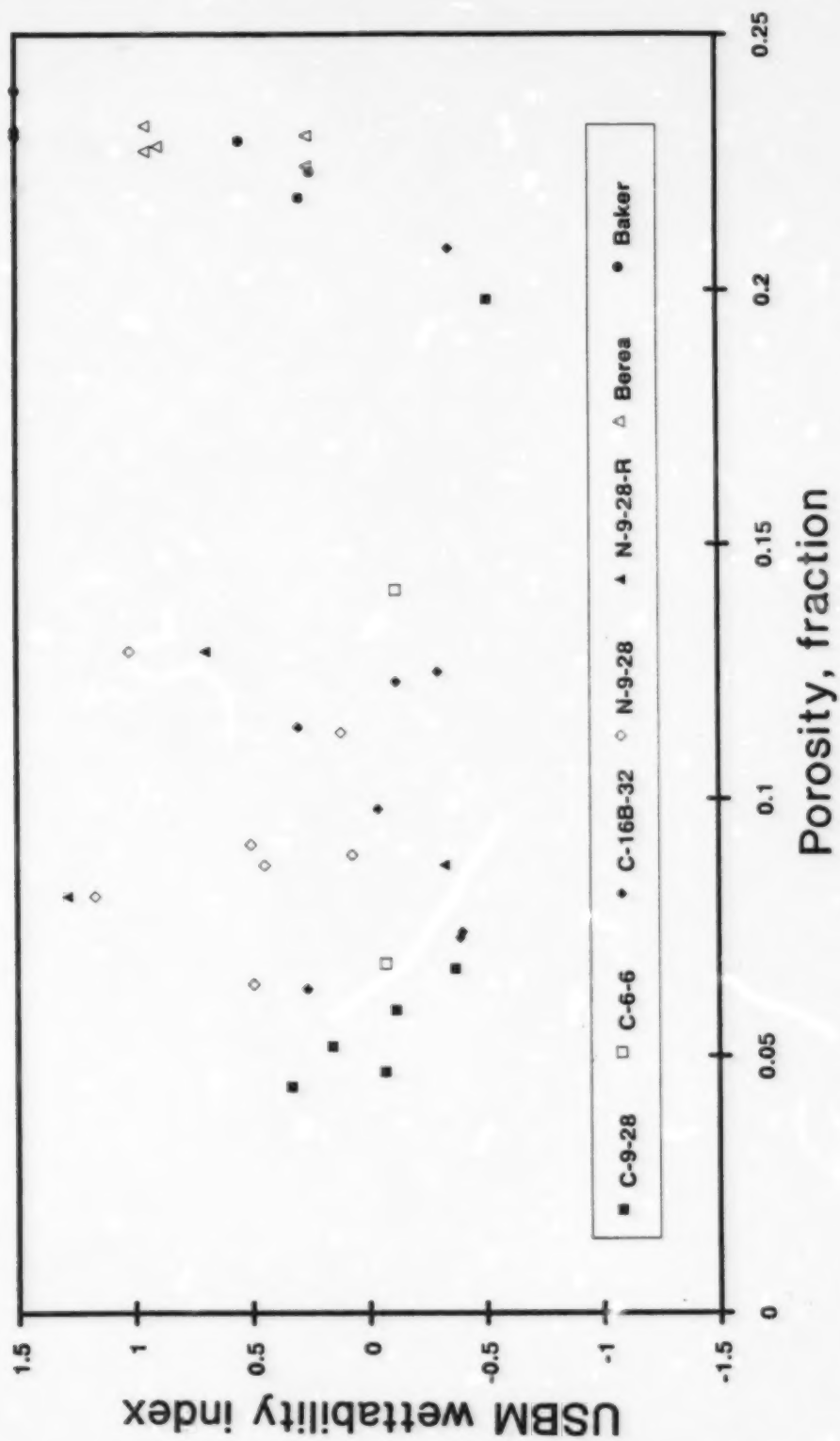


Figure 108: USBM Wettability Index as a function of porosity.

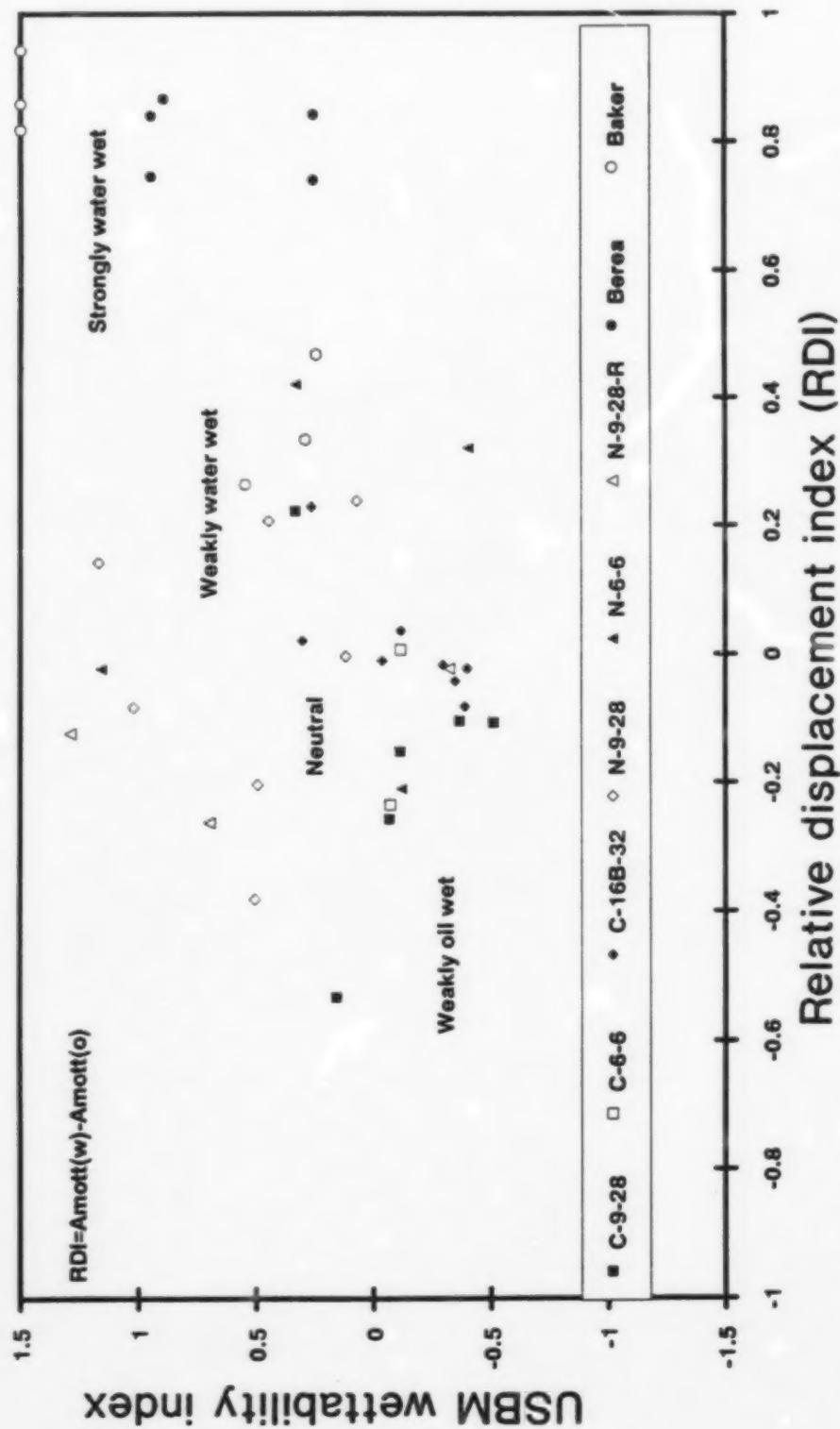


Figure 109: USBM wettability index as a function of the Relative Displacement Index (RDI).

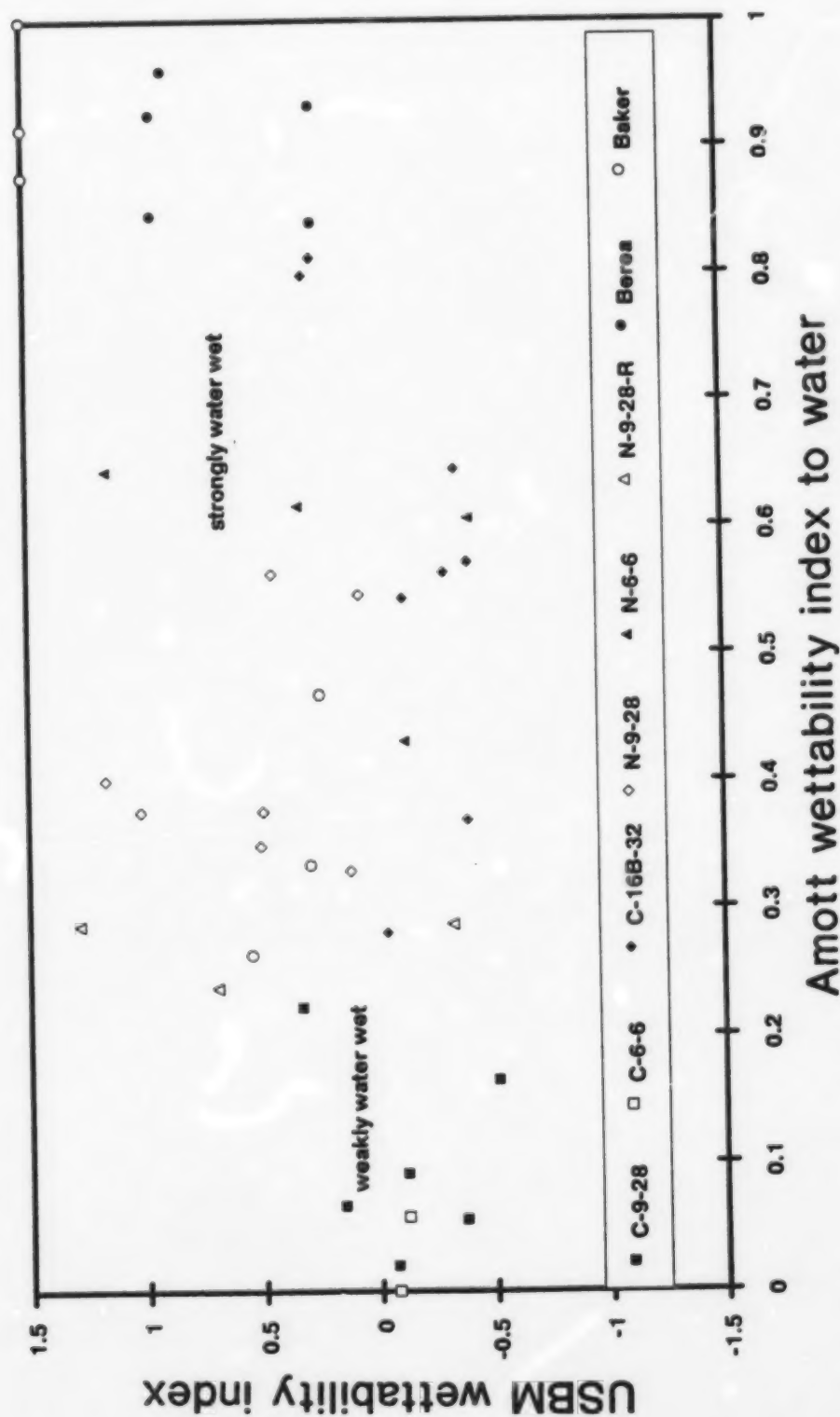


Figure 110: USBM index as a function of the Amott wettability index to water.

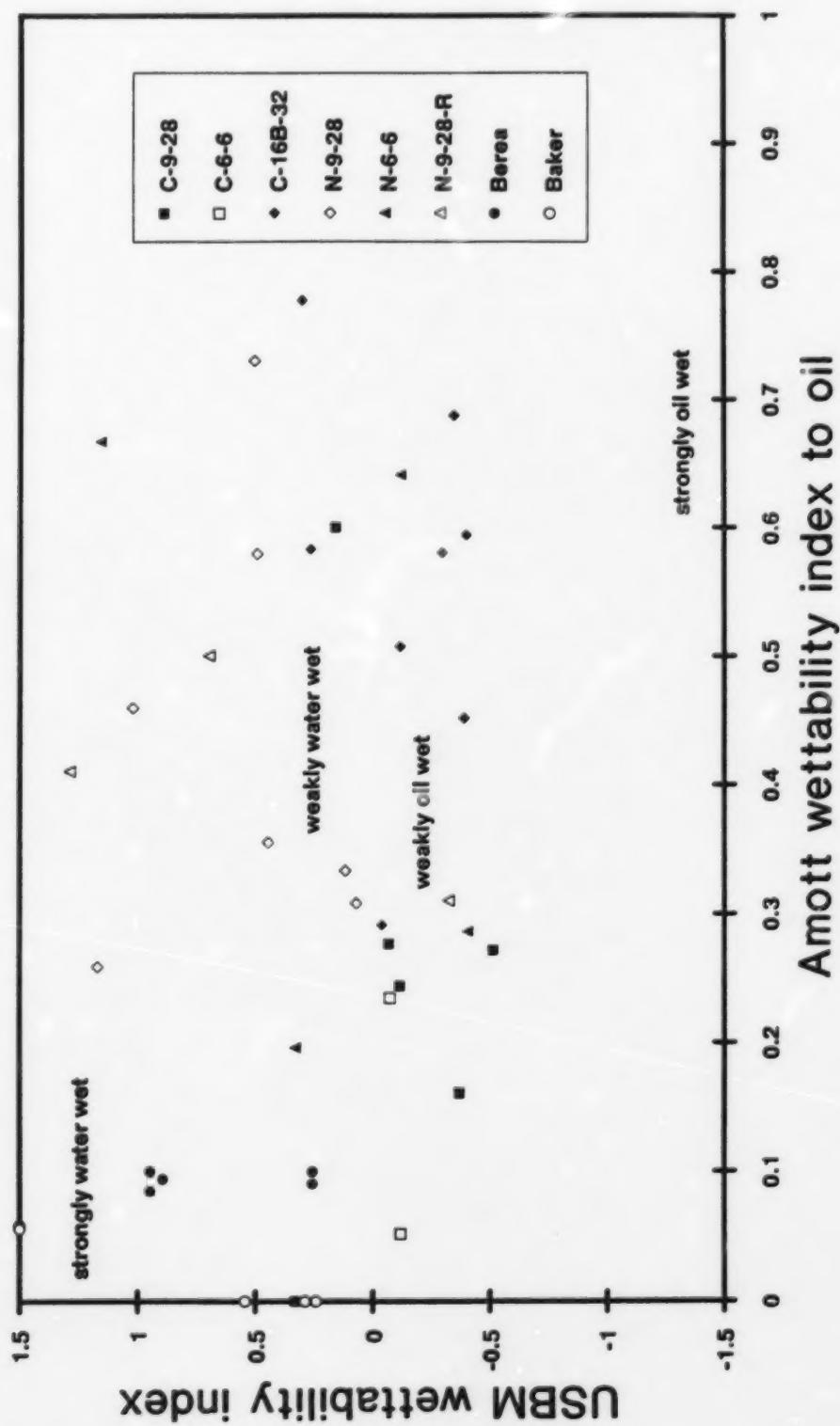


Figure 111: USBM Index as a function of the Amott Wettability Index to oil.

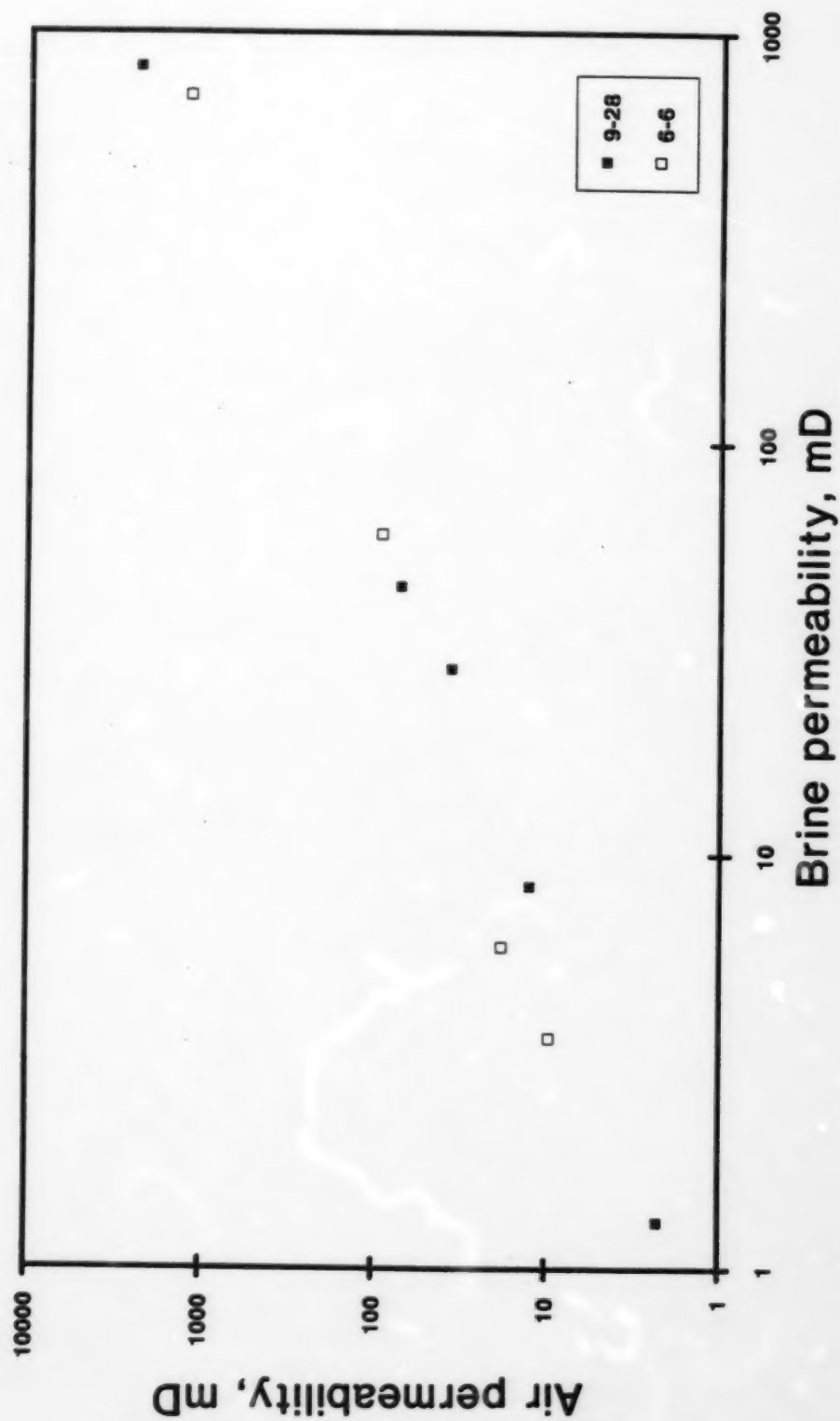


Figure 112: Air/brine permeability plots for the RKR "F" Pool plugs.

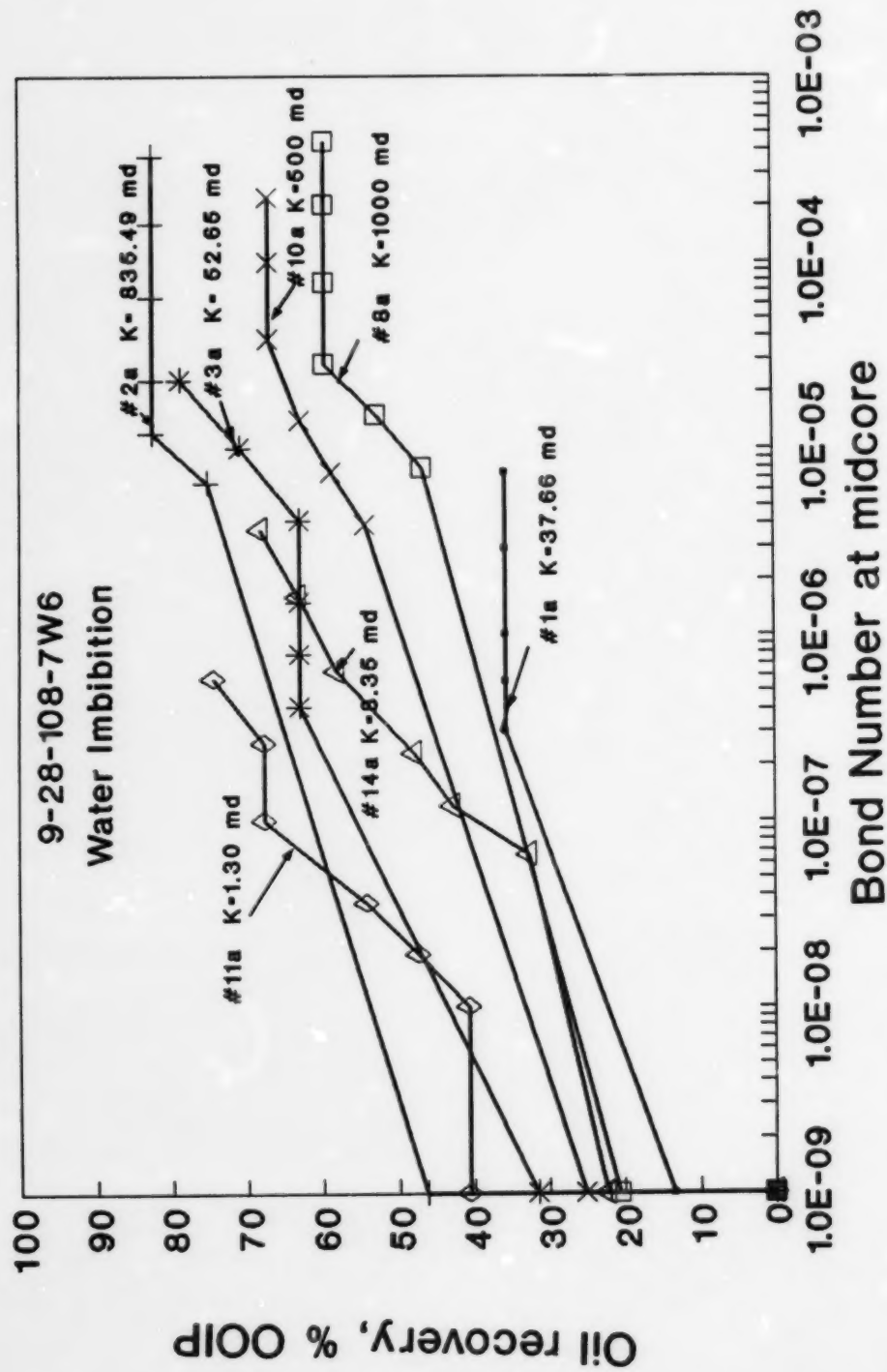


Figure 113: Waterflood recovery plot for the 9-28 plugs.

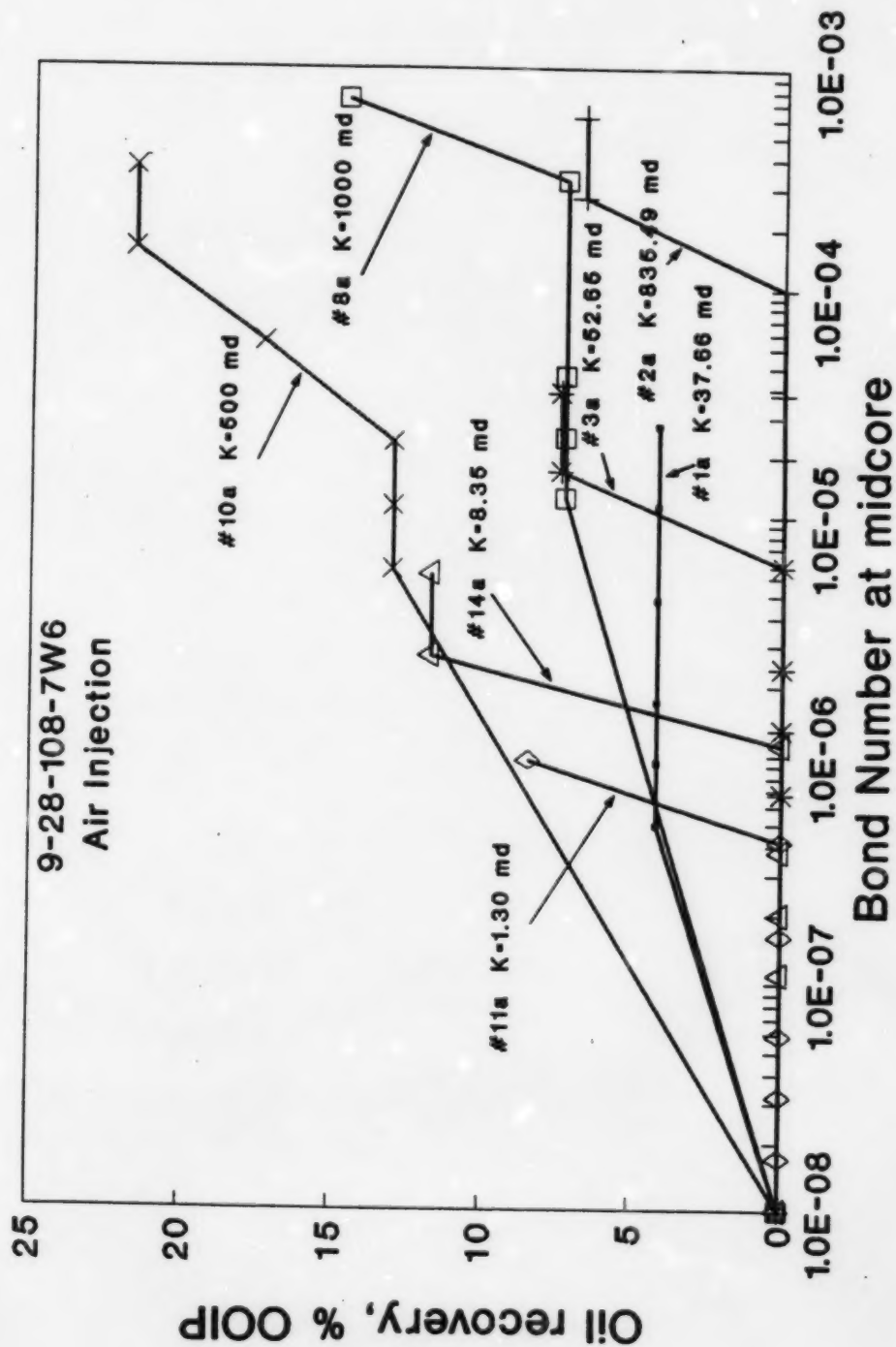


Figure 114: Gasflood recovery plots for the 9-28 plugs.

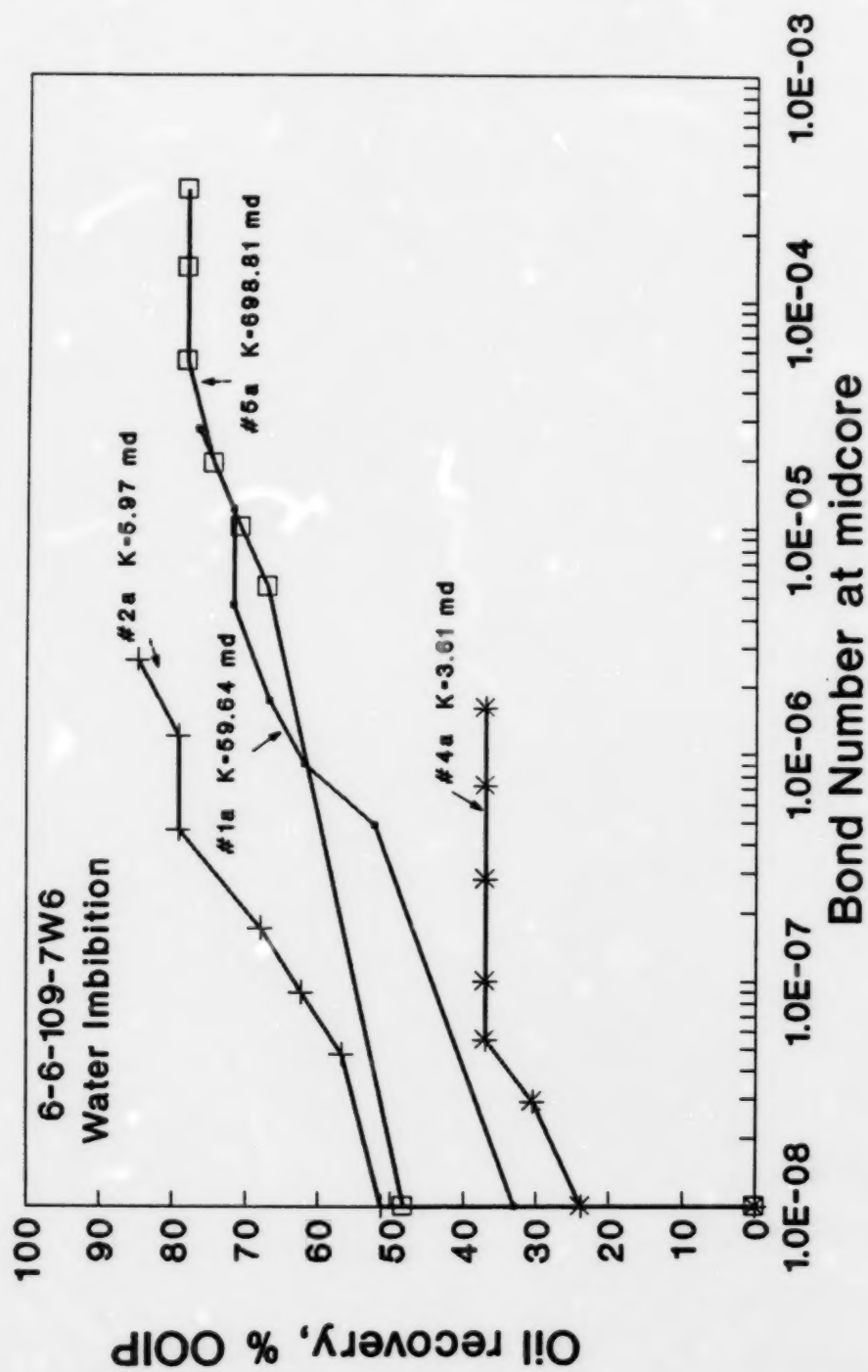


Figure 115: Waterflood recovery plot for the 6-6 plugs.

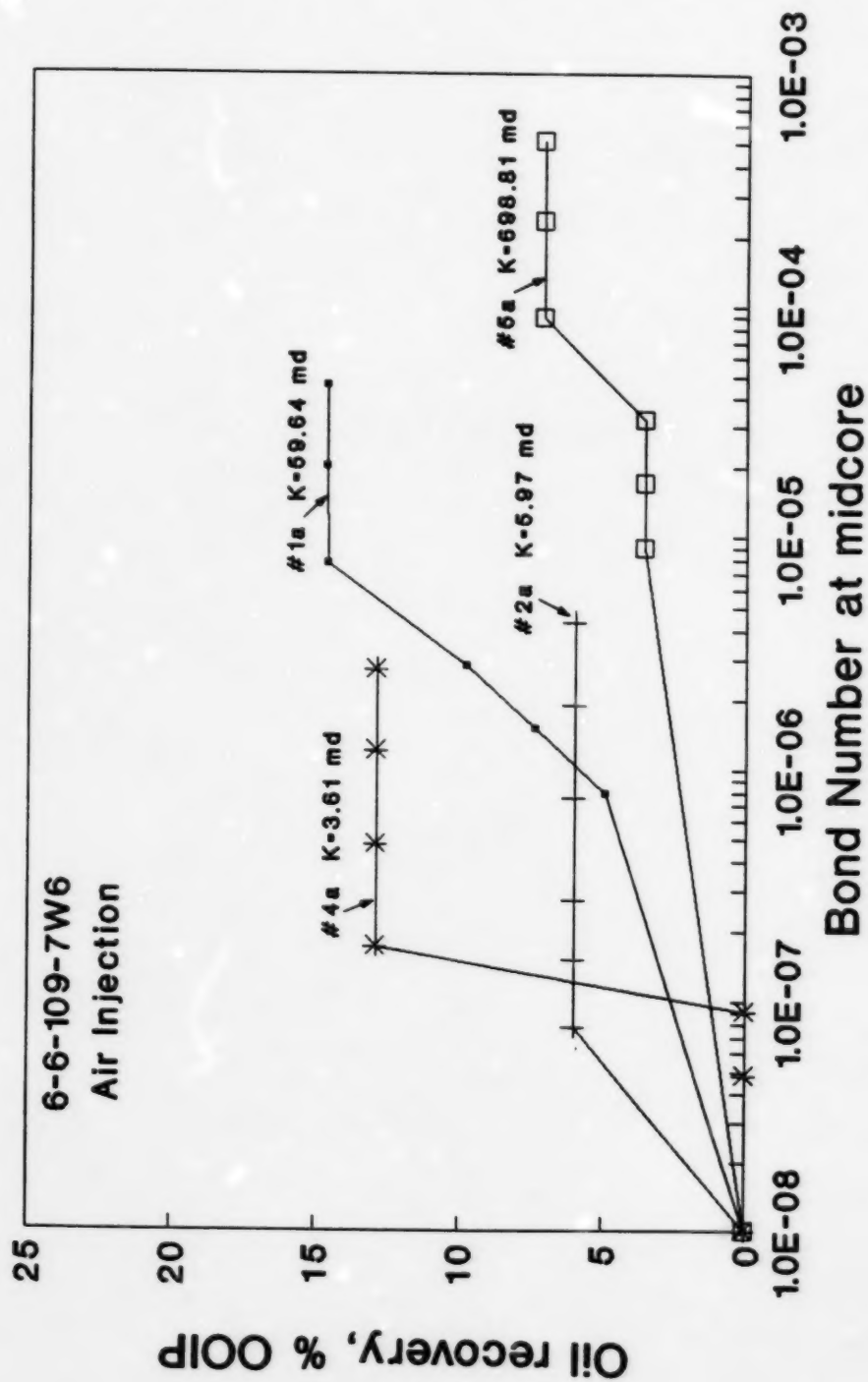


Figure 116: Gasflood recovery plot for the 6-6 plugs.

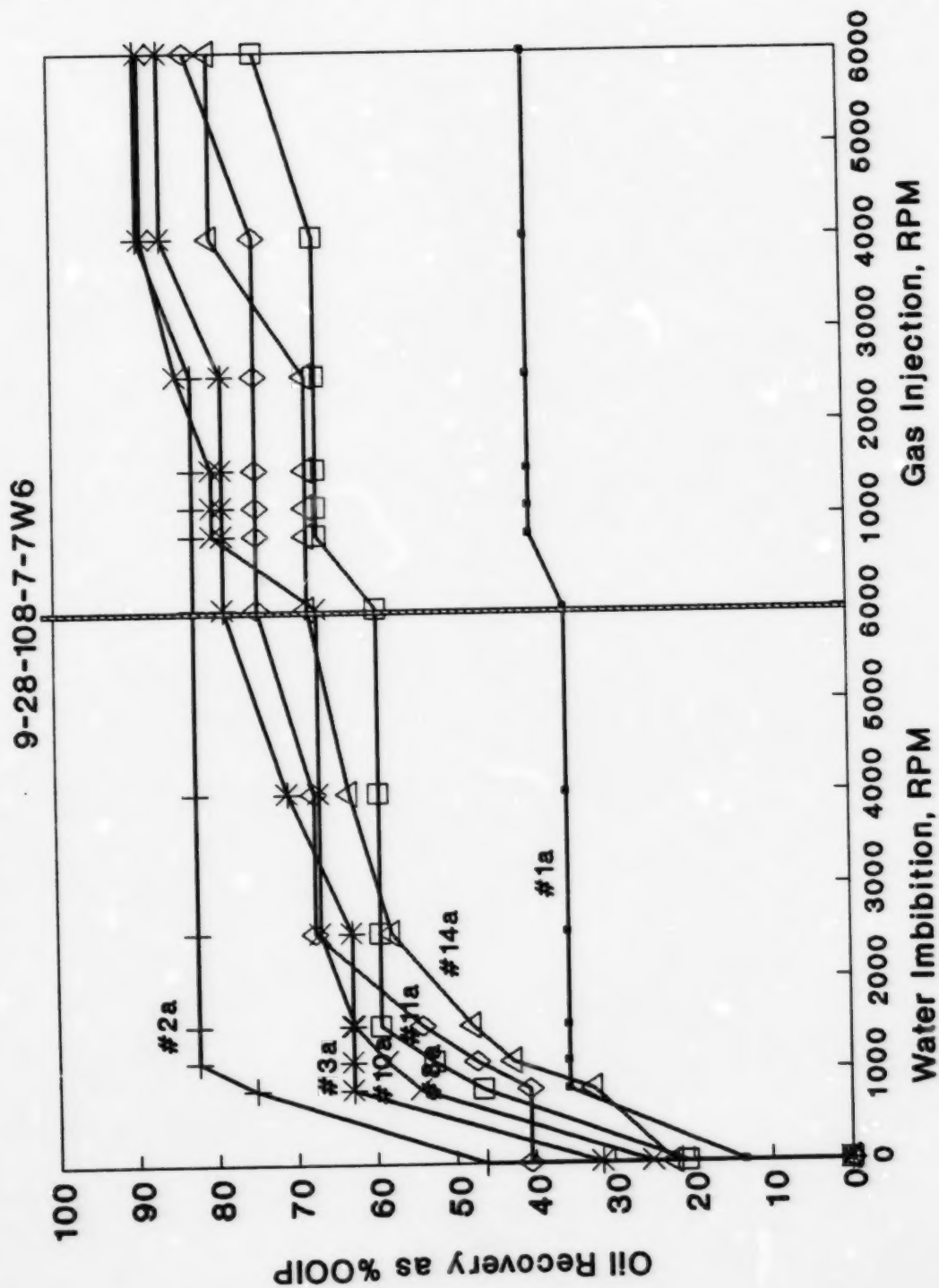


Figure 117: Oil recovery from the 9-28 plugs.

6-6-109-7W6

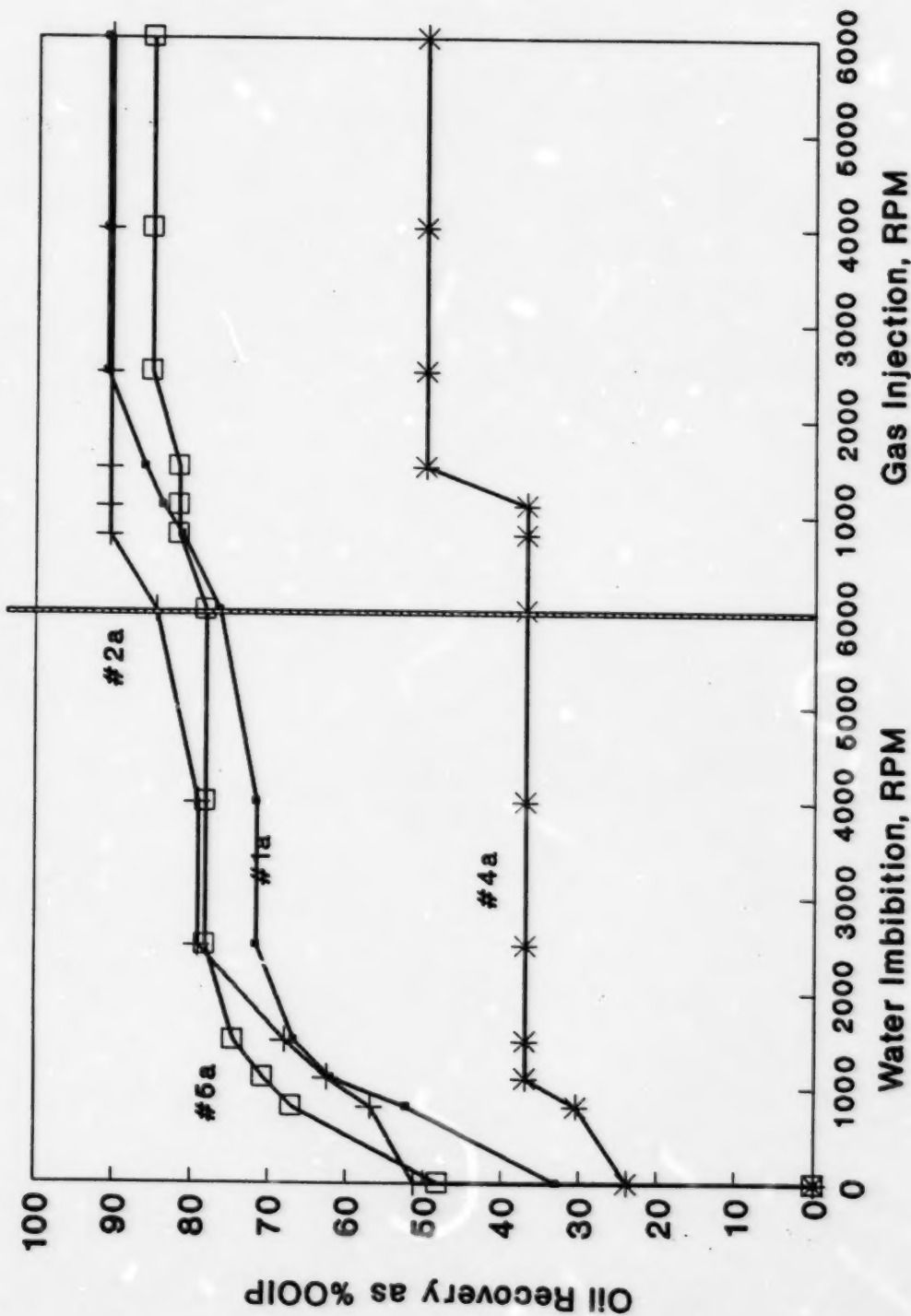


Figure 118: Oil recovery from the 6-6 plugs.

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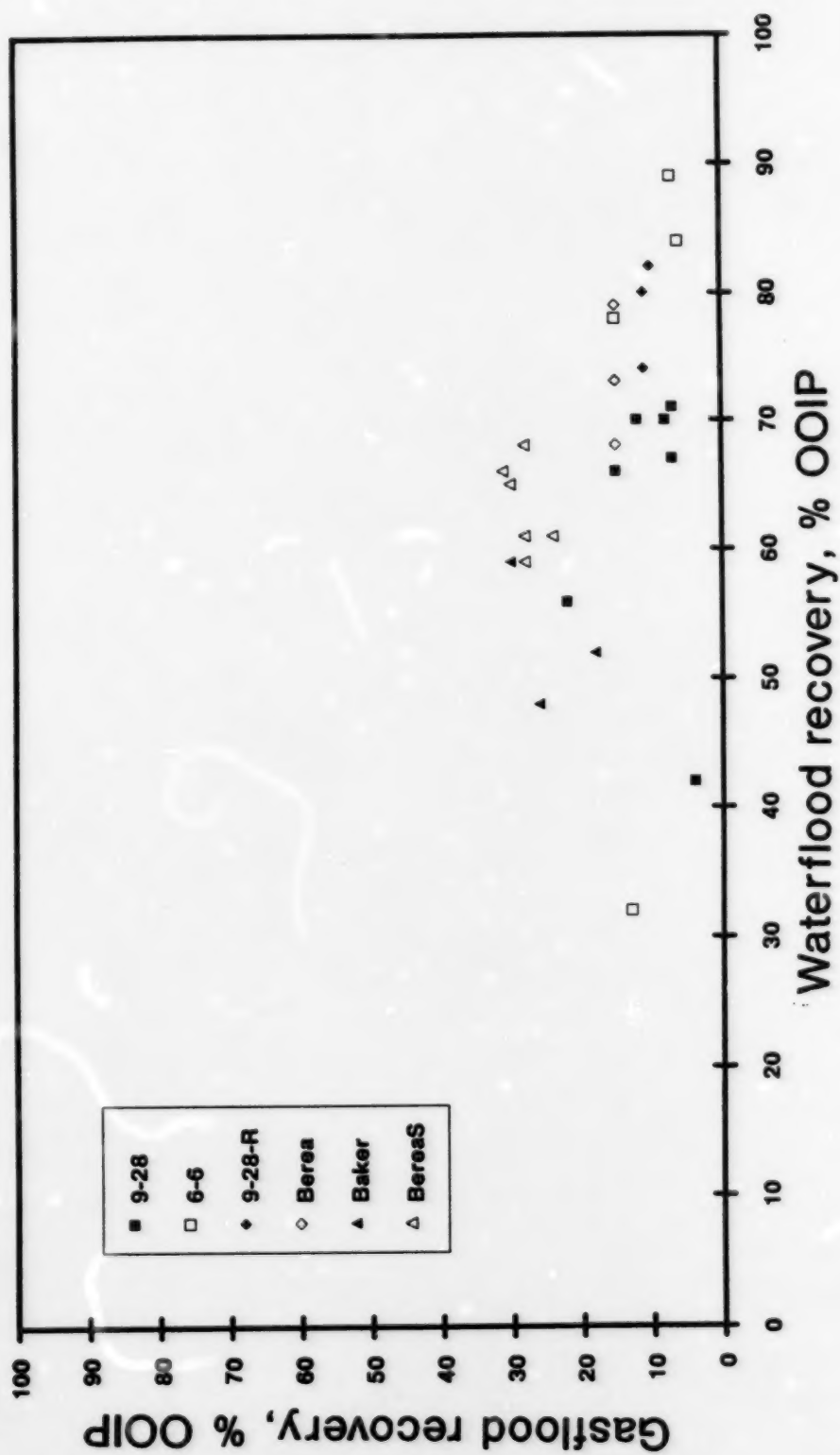


Figure 119: Gasflood recovery as a function of waterflood recovery for the centrifuge tests.

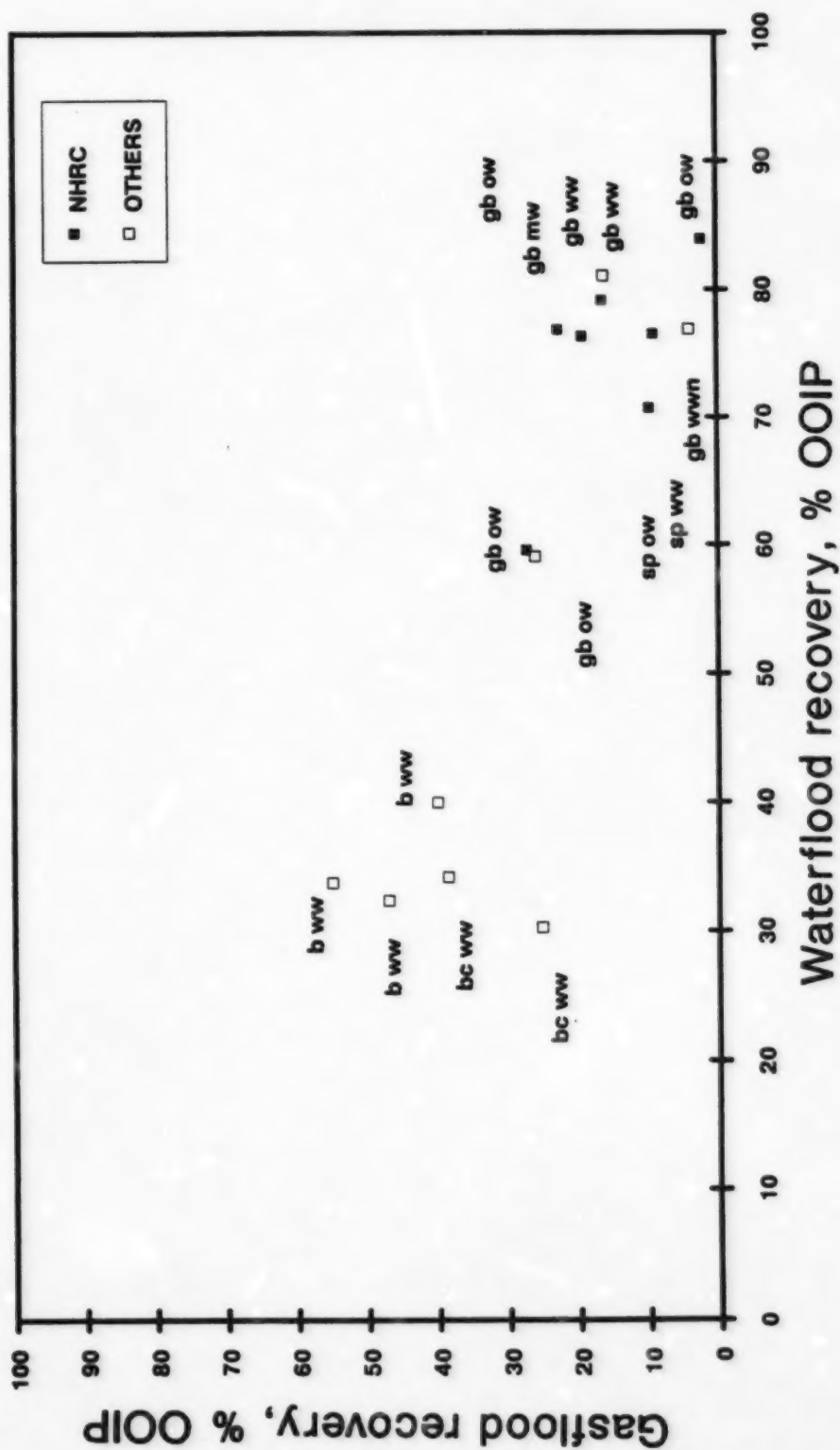


Figure 120: Gasflood recovery as a function of waterflood recovery for the ambient corefloods.

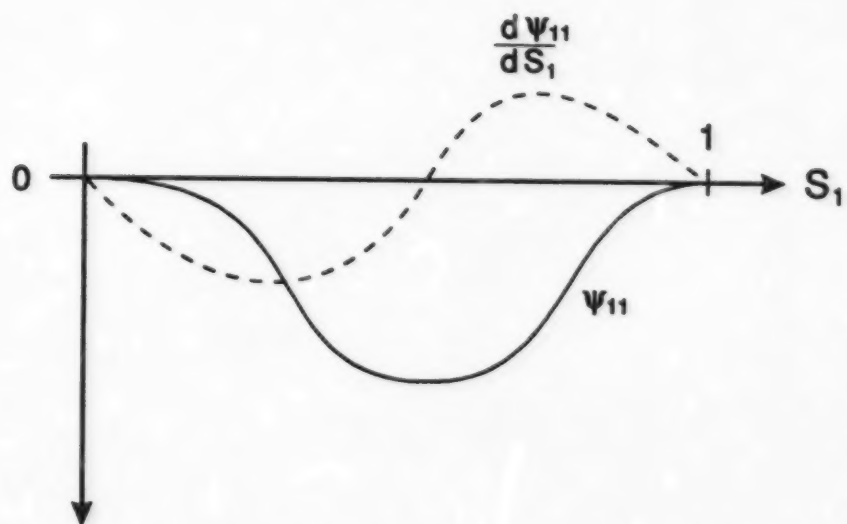
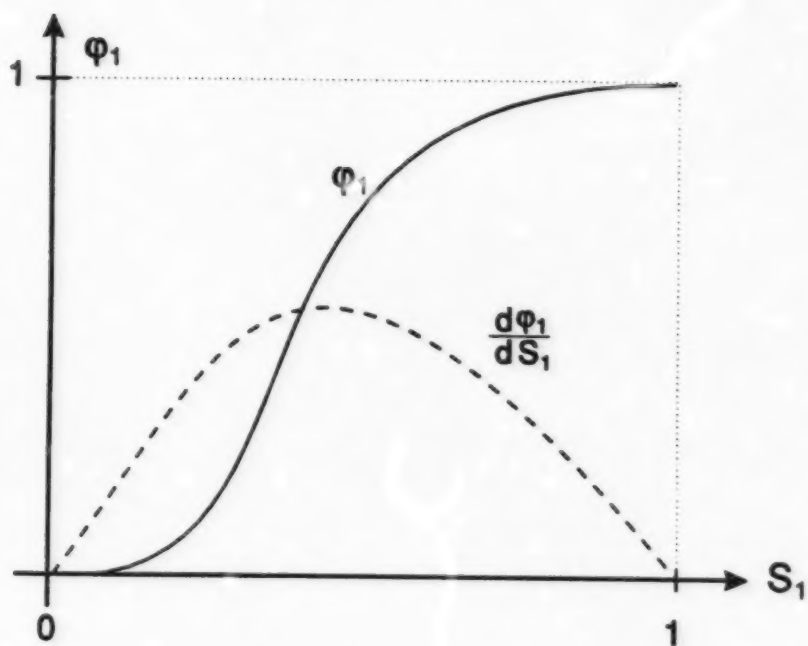


Figure 121: A typical shape of curves ϕ_1 and ψ_{11}

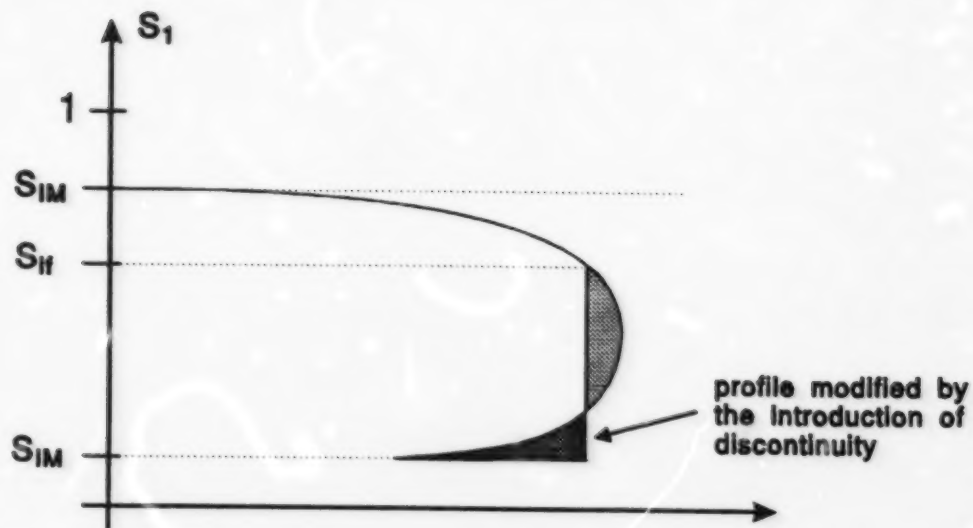


Figure 122: The theoretical profile of saturation

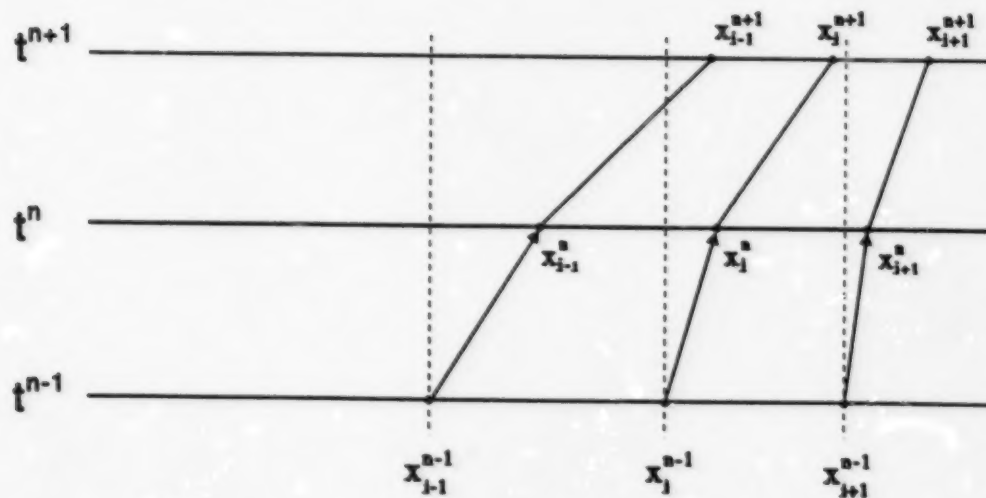


Figure 123: Illustration of the dynamic grid procedure

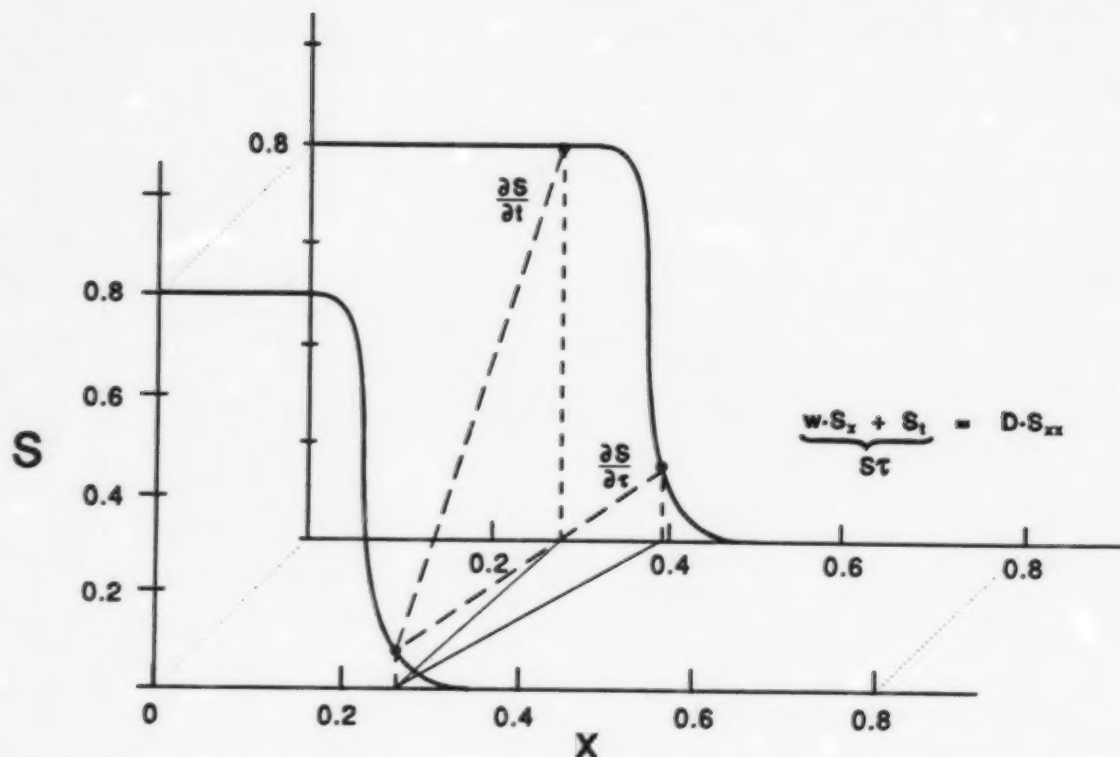


Figure 124: A discretization scheme based on the method of characteristics

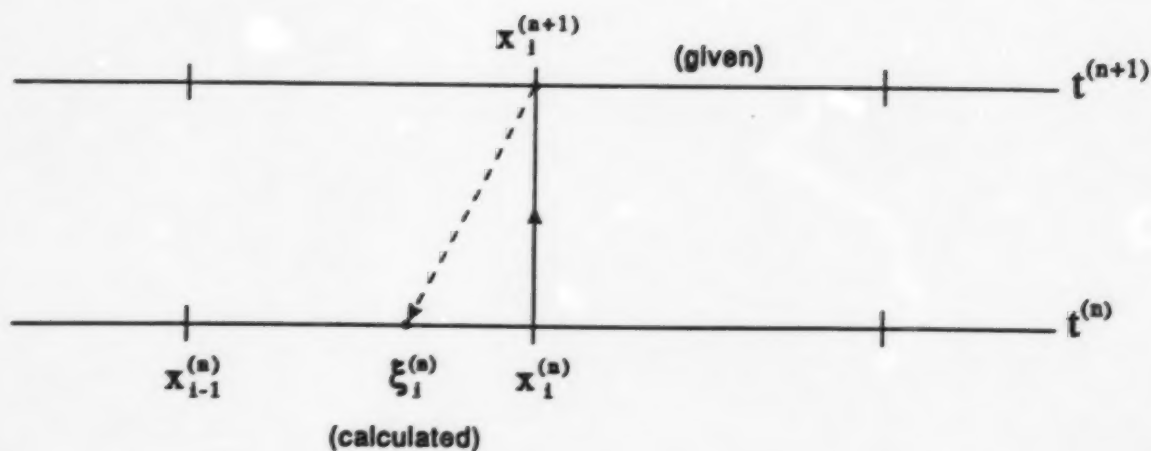


Figure 125: Illustration of the back projection procedure

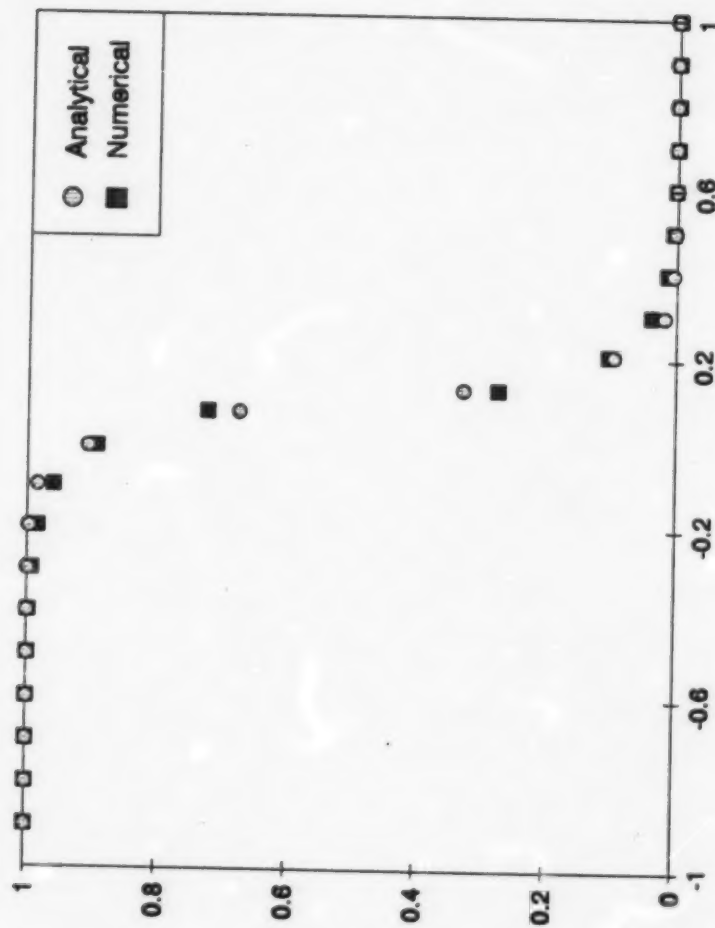


Figure 126: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.1$)

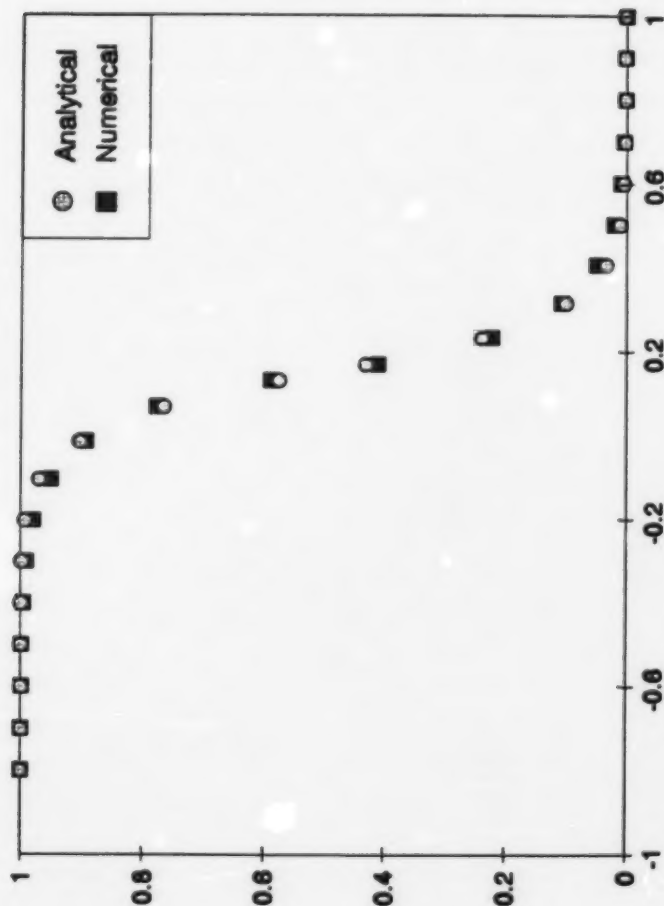


Figure 127: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.2$)

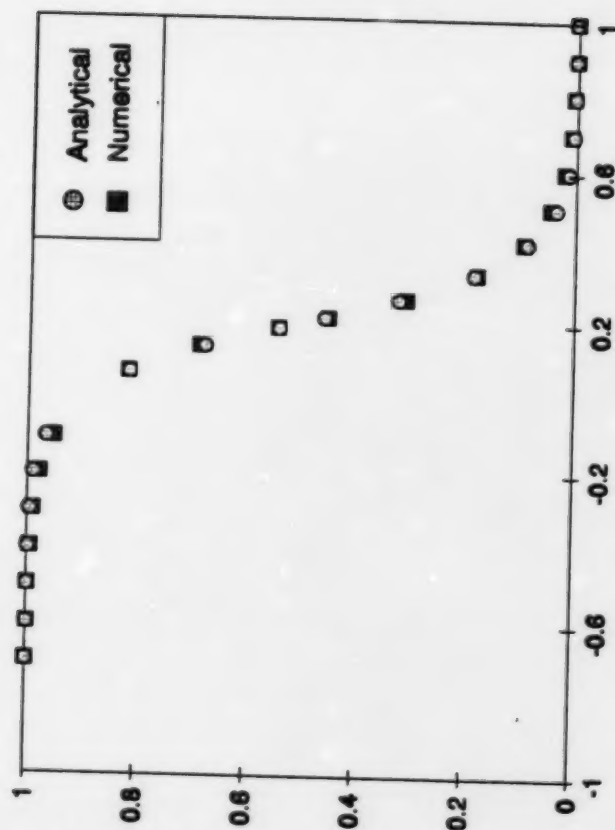


Figure 128: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($\tau = 0.3$)

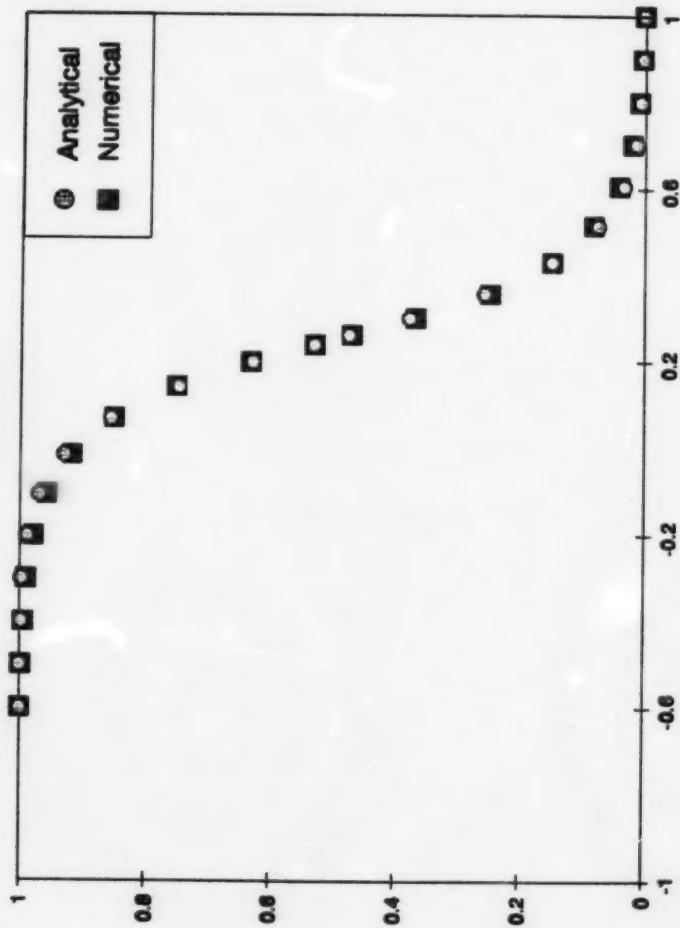


Figure 129: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.4$)

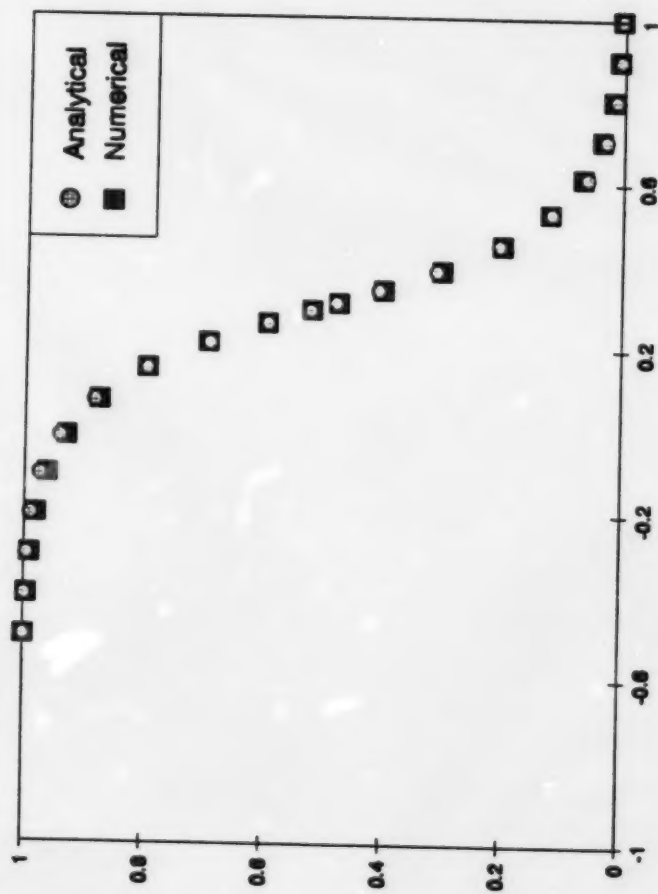


Figure 130: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.5$)

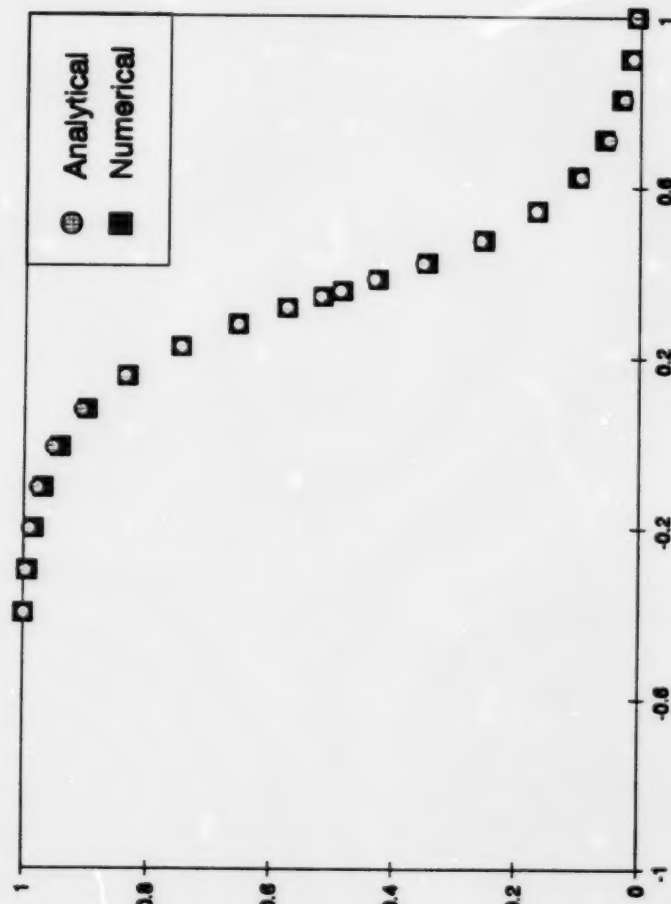


Figure 131: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.6$)

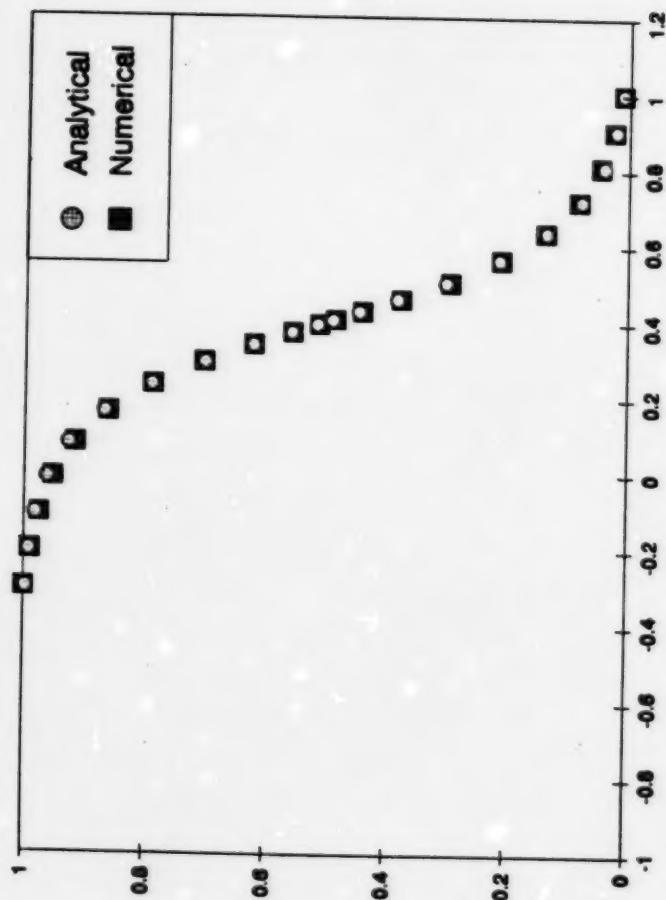


Figure 132: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.7$)

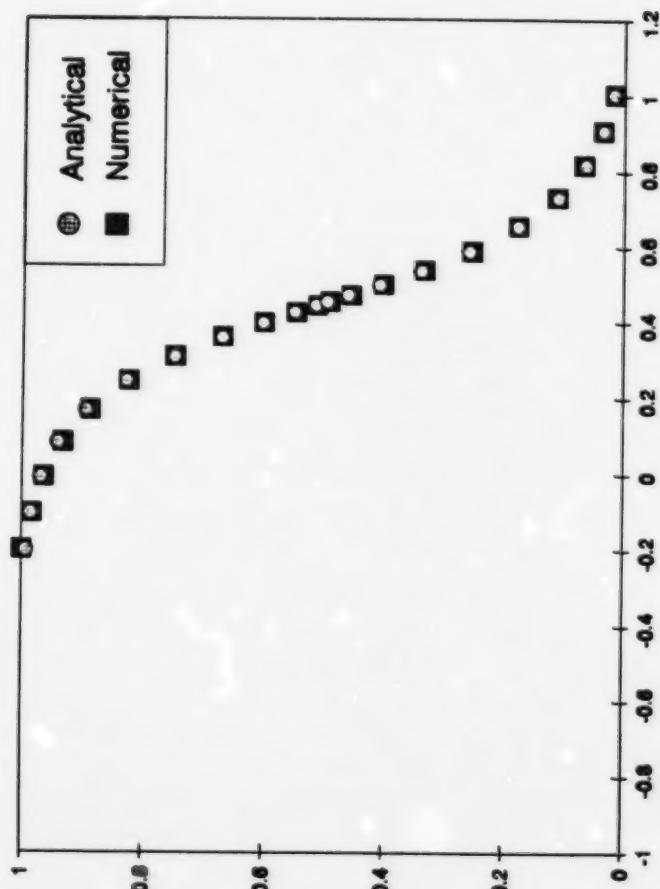


Figure 133: Exact and numerical solution of Burger's equation using Implicit scheme with dynamic grid ($t = 0.8$)

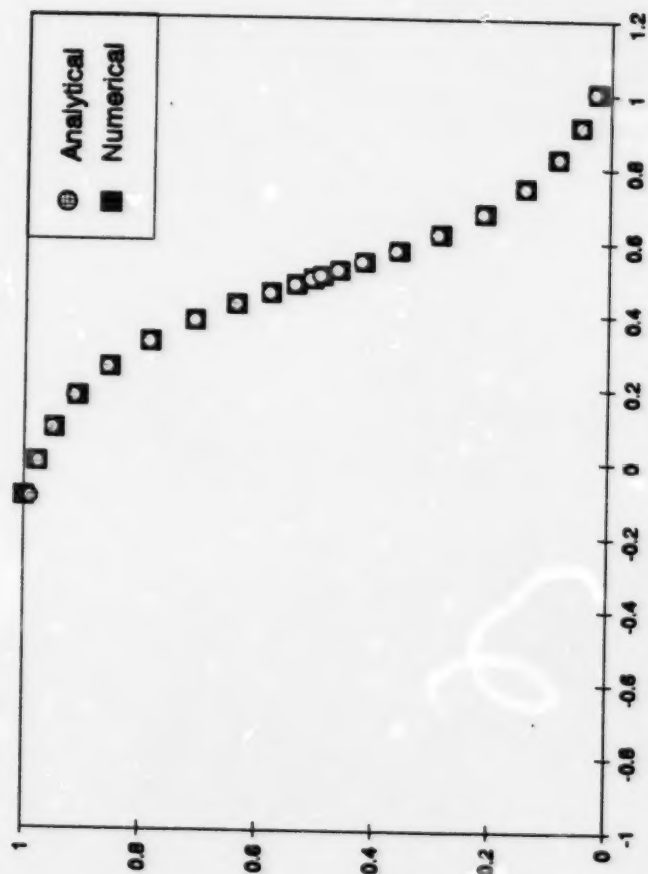


Figure 134: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.9$)

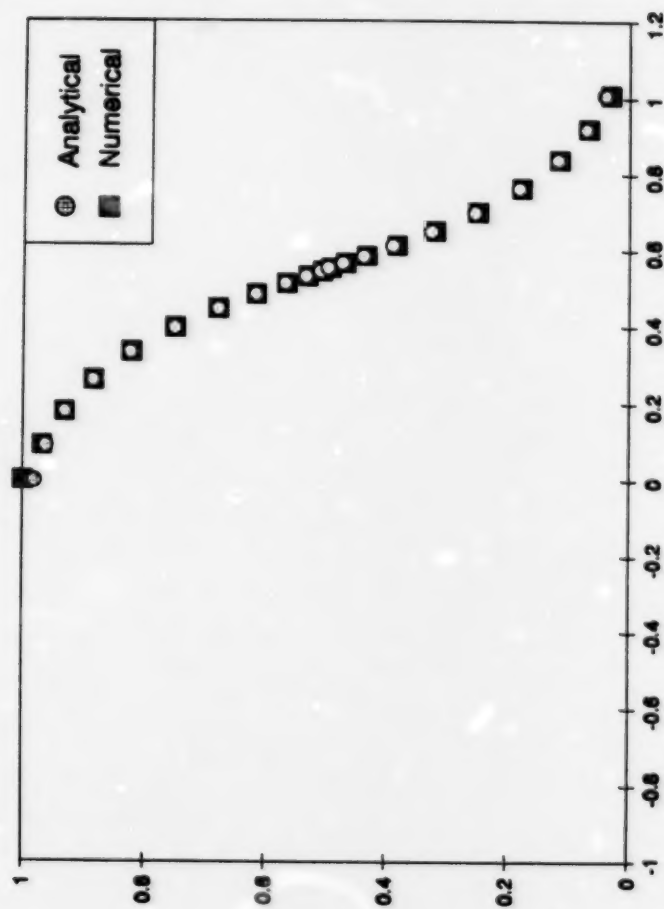


Figure 135: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 1.0$)

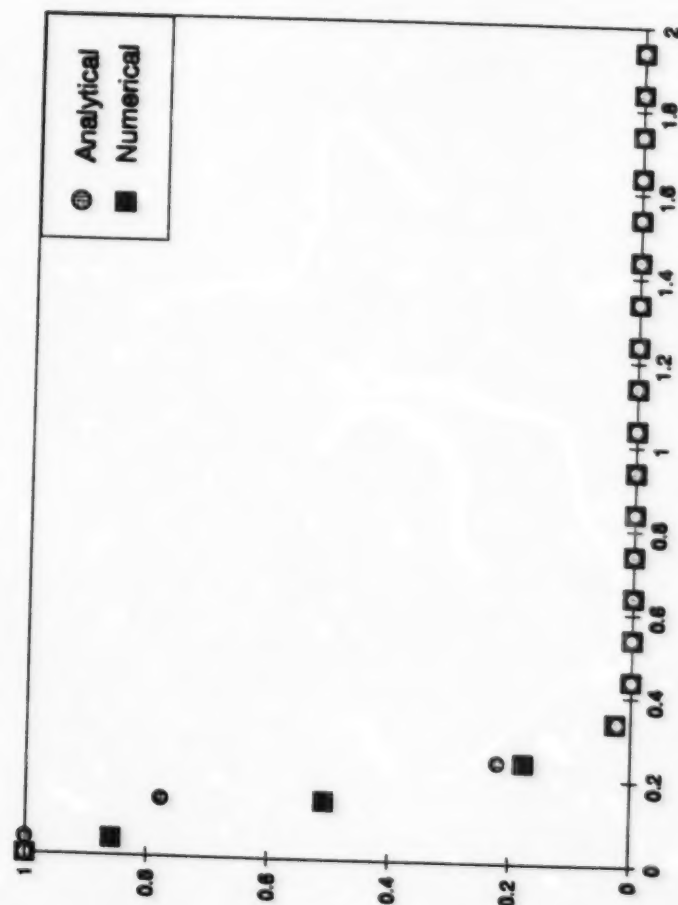


Figure 136: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.2$)

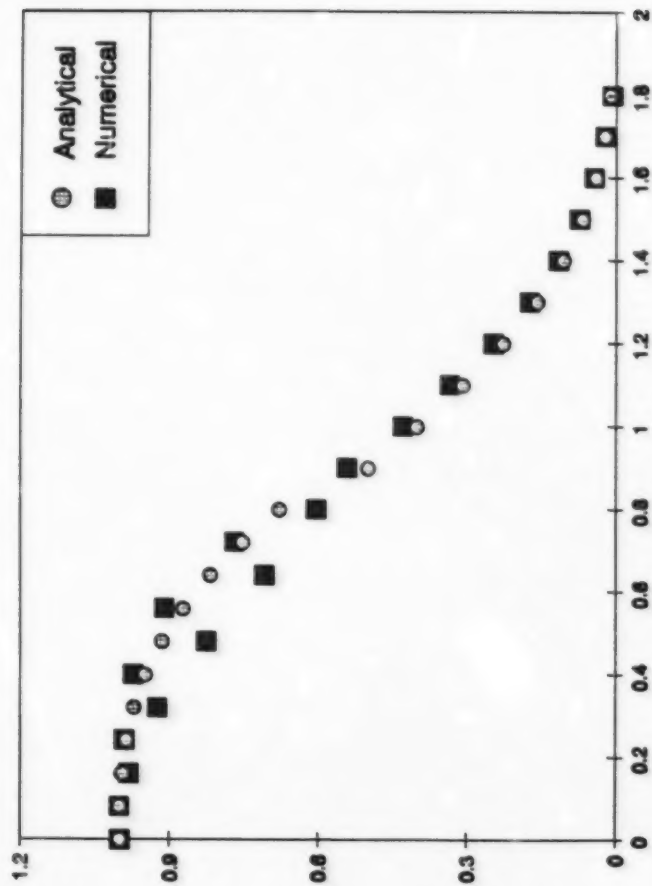


Figure 137: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 4.0$)

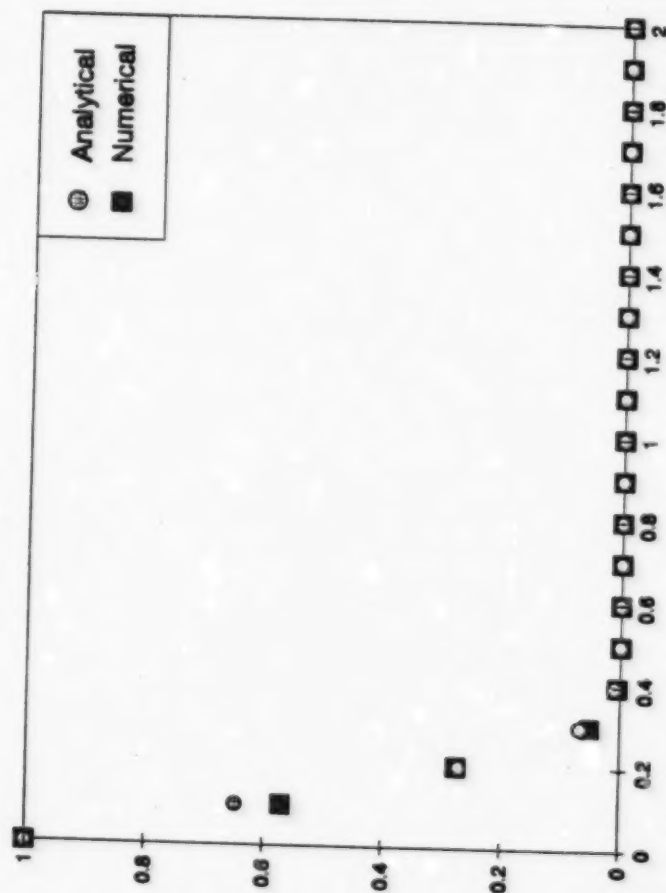


Figure 138: Exact and numerical solution of Burger's equation using Implicit scheme with dynamic grid ($t = 0.2$)

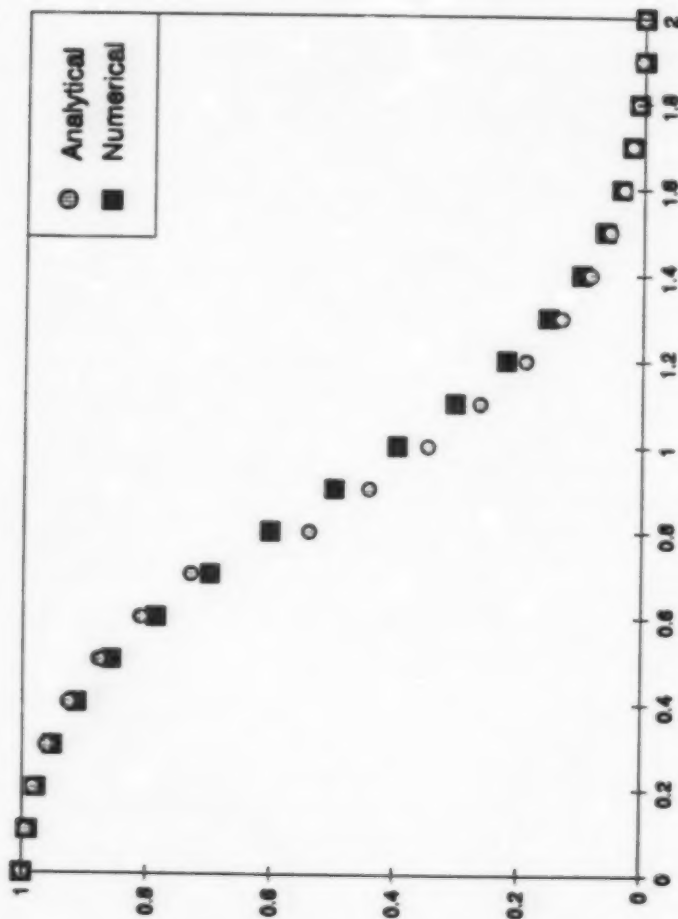


Figure 139: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 4.0$)

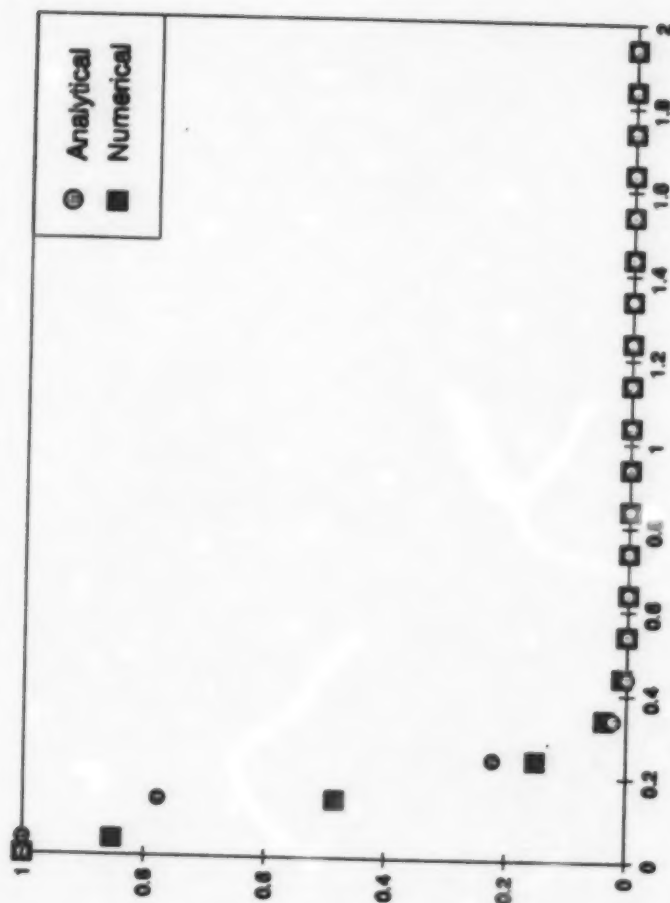


Figure 140: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($\tau = 0.2$)

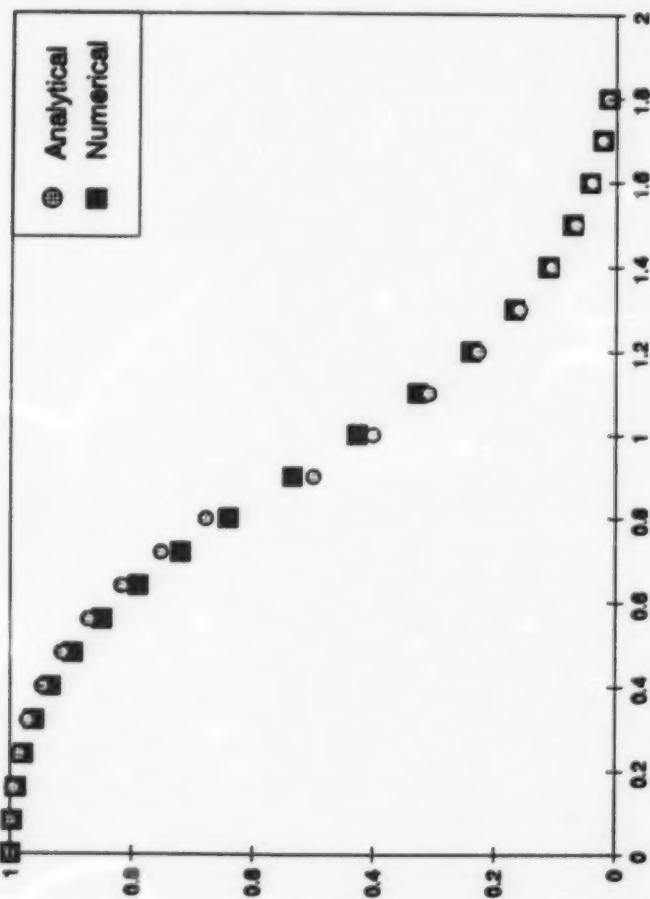


Figure 141: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 4.0$)

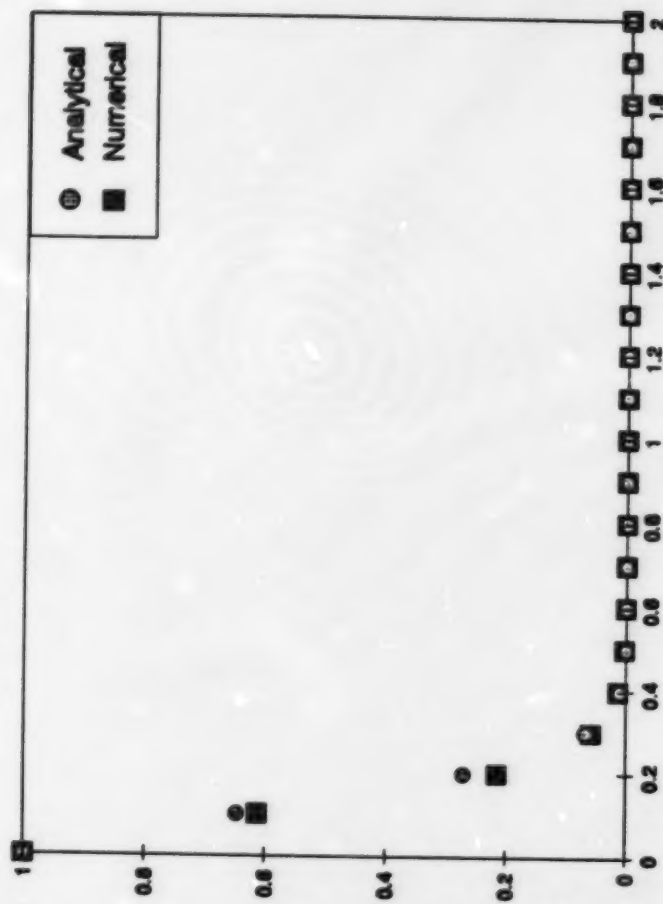


Figure 142: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 0.2$)

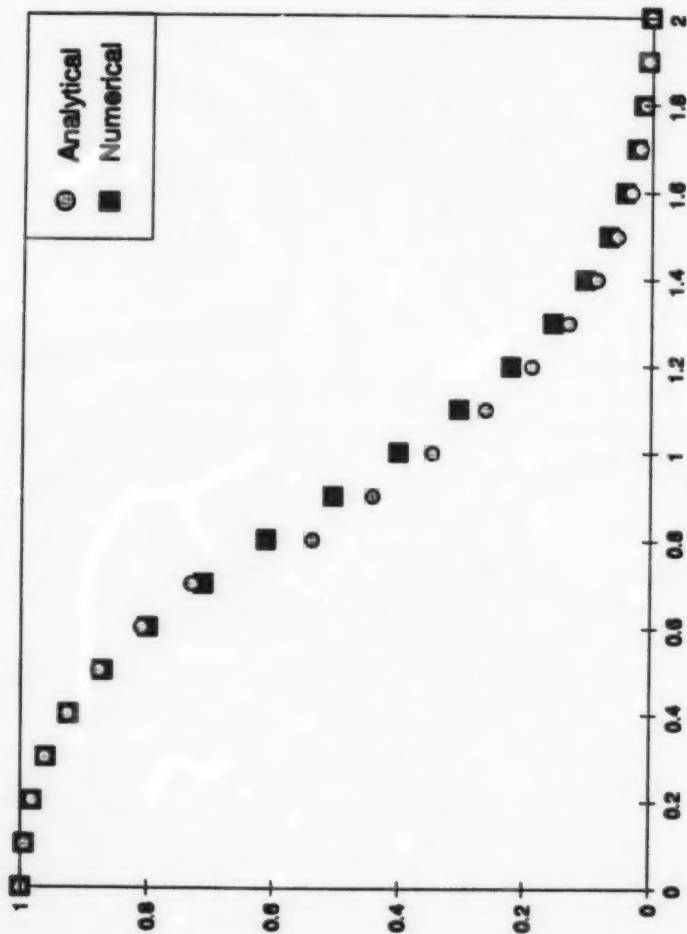


Figure 143: Exact and numerical solution of Burger's equation using implicit scheme with dynamic grid ($t = 4.0$)

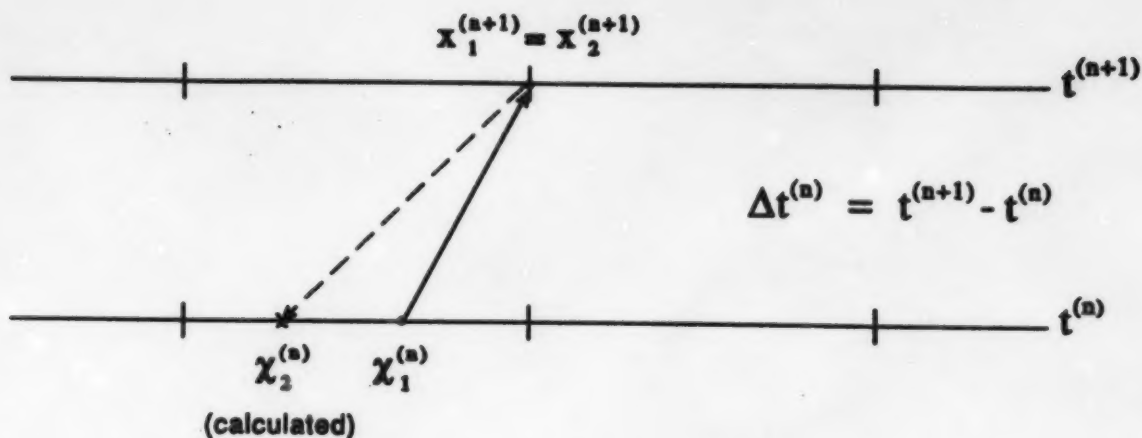


Figure 144: Illustration of the back projection procedure with dynamic grid

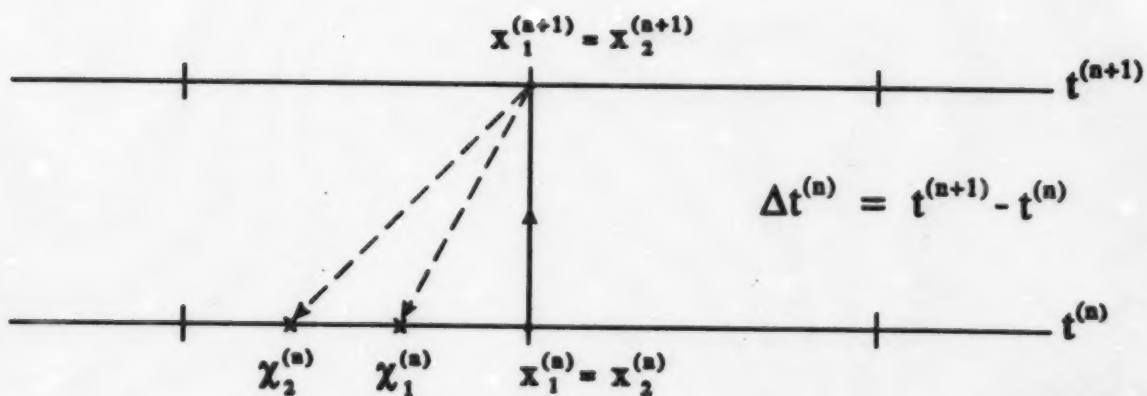


Figure 145: Illustration of the back projection procedure with a static grid

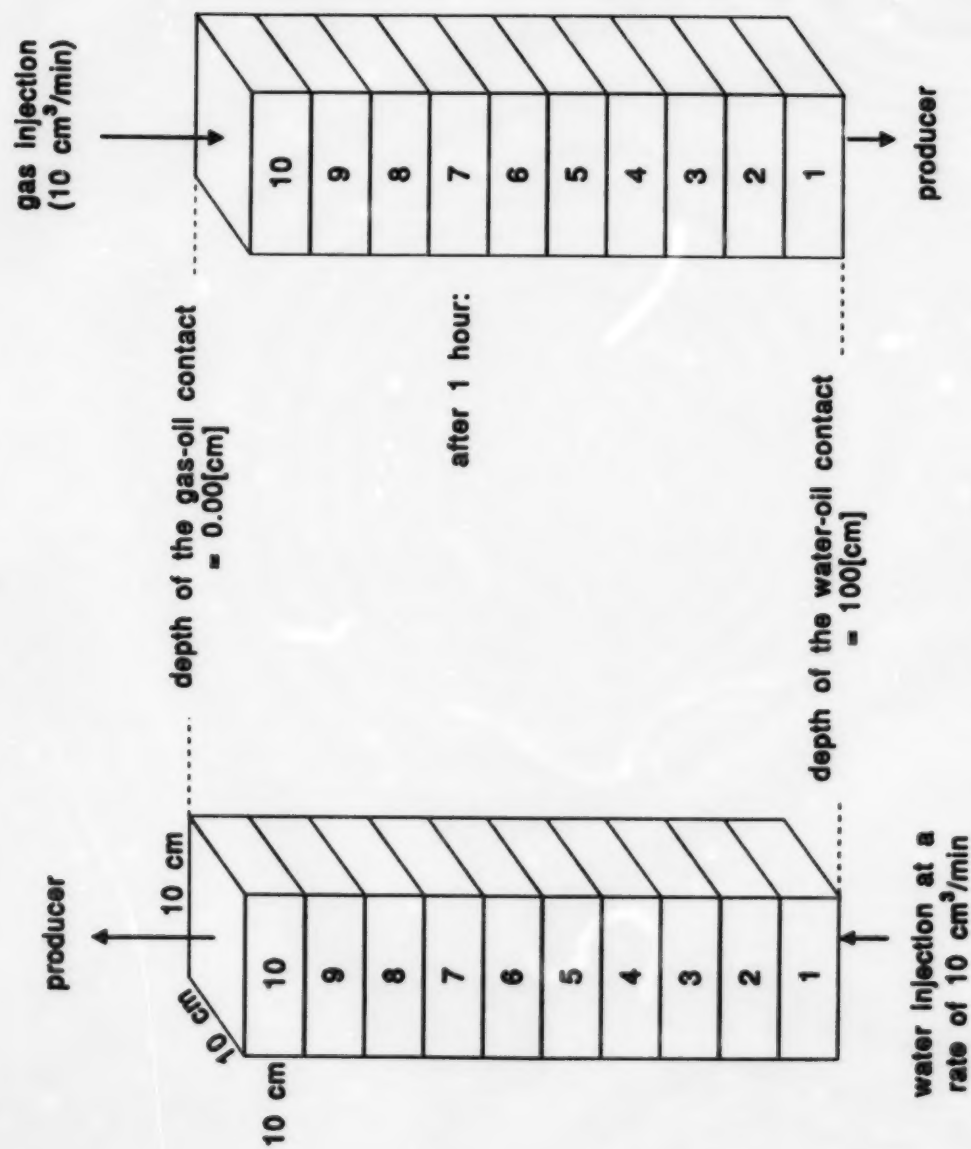


Figure 146: A water/gas flooding model using IMEX and its dimensions

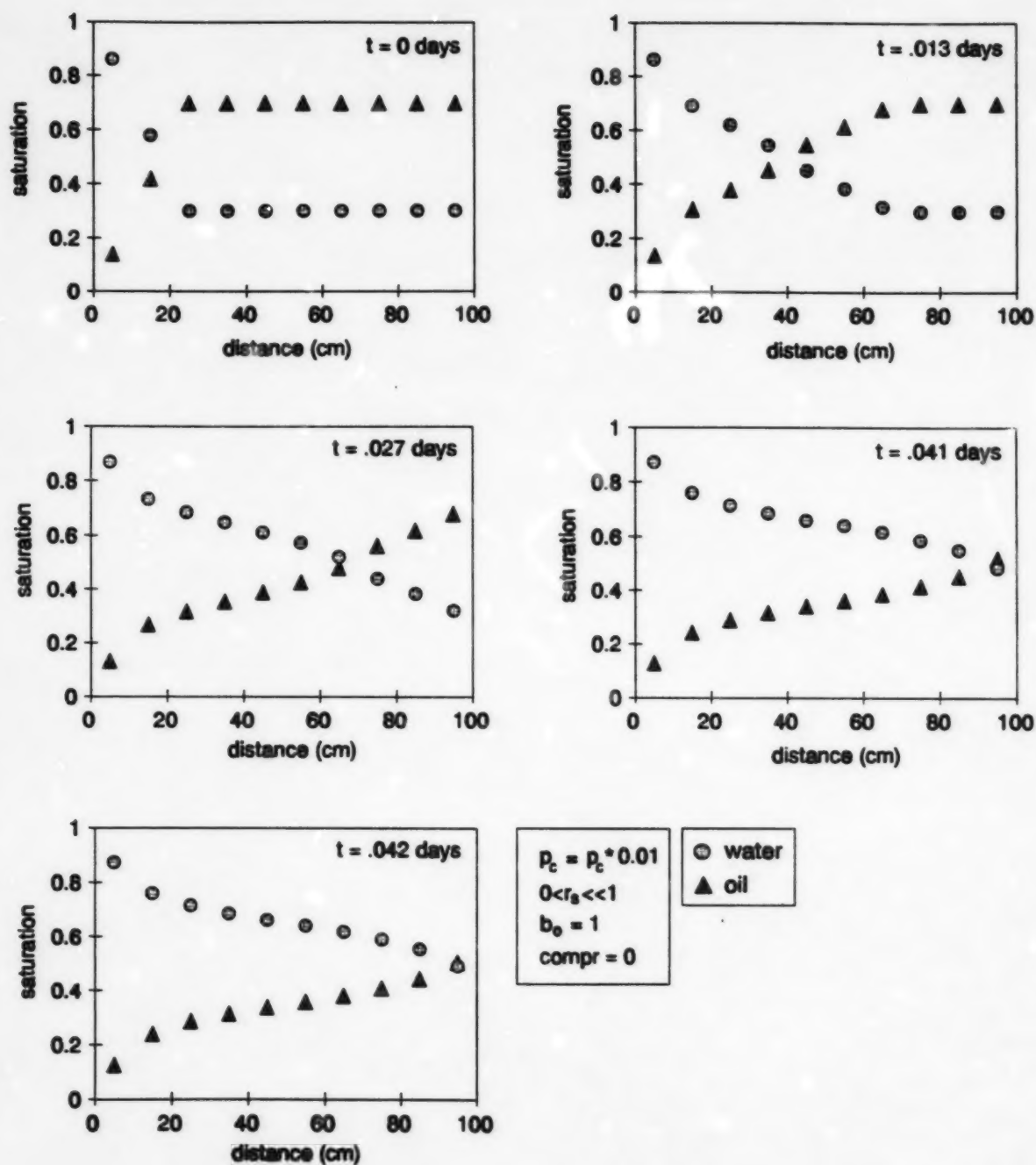


Figure 147: Saturation profiles of oil and water. P_c reduced 100 times B_o set to 1.0

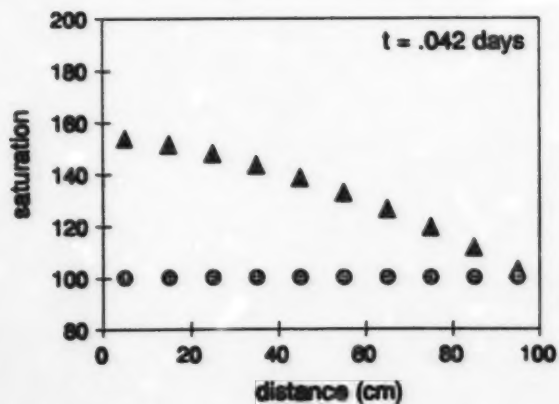
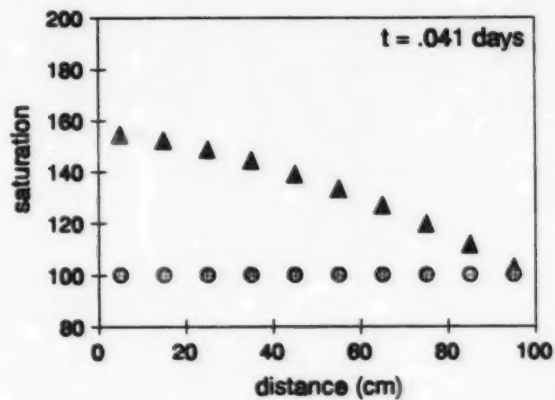
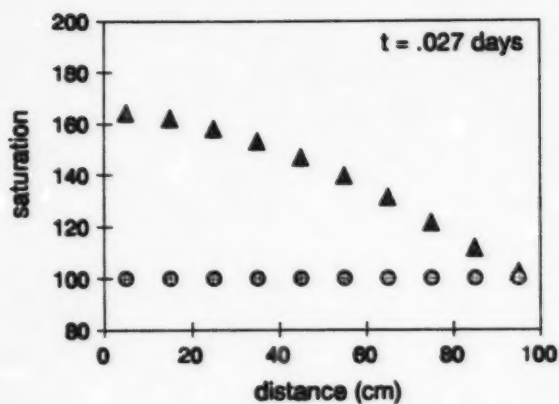
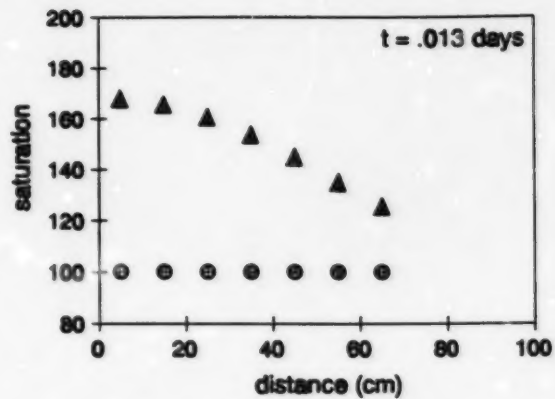
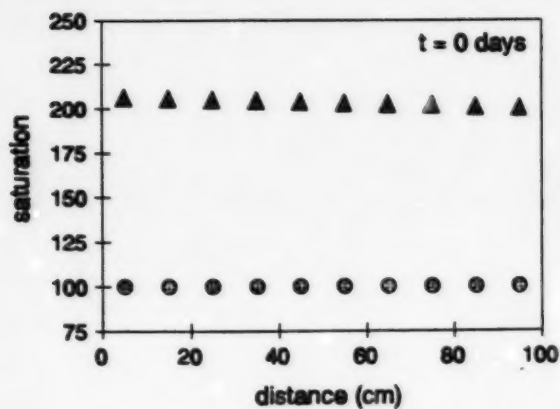
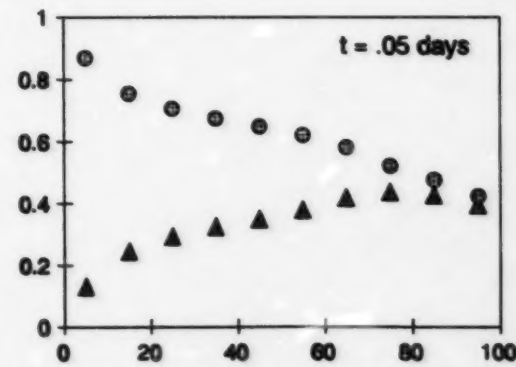
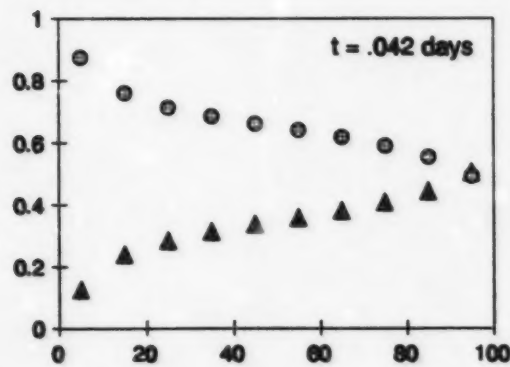
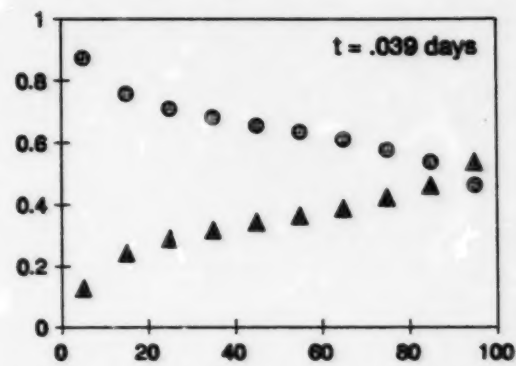
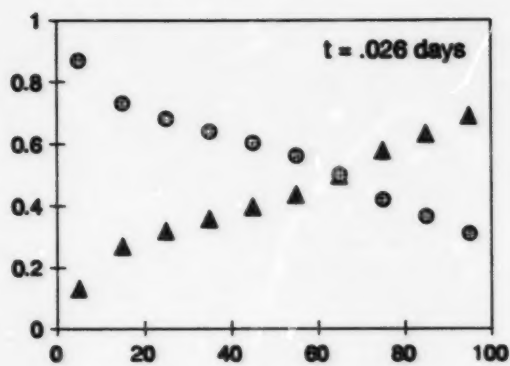
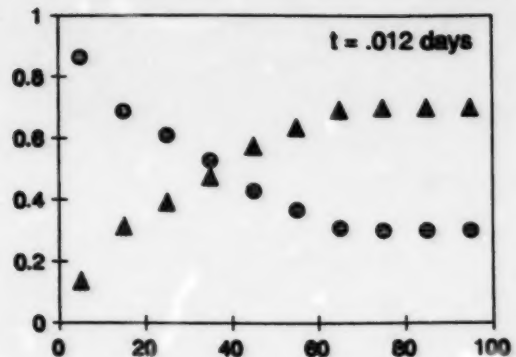
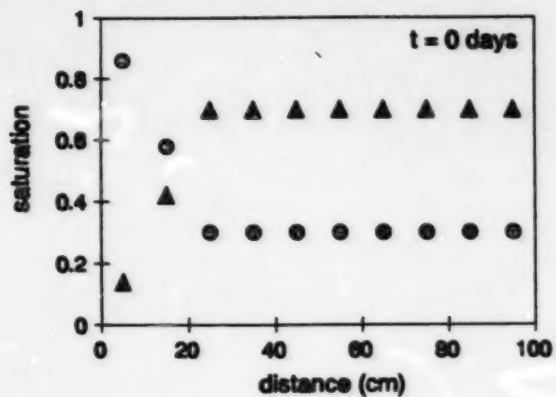
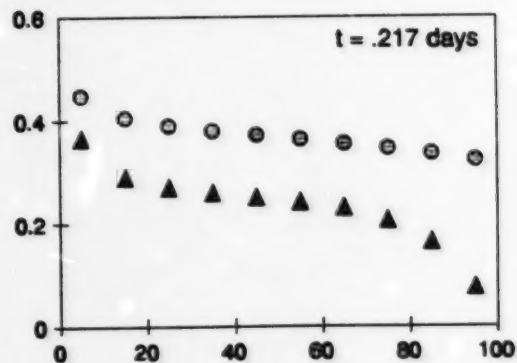
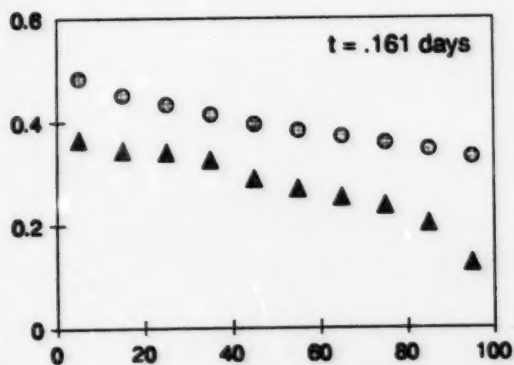
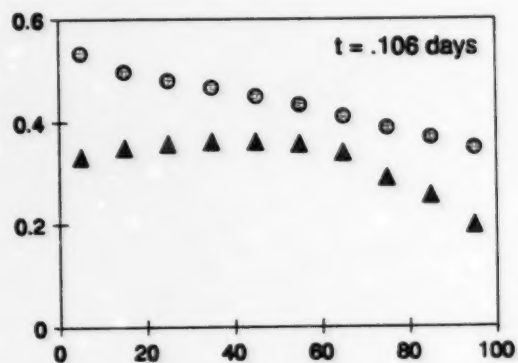
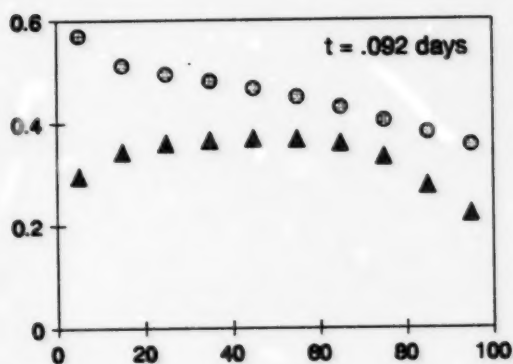
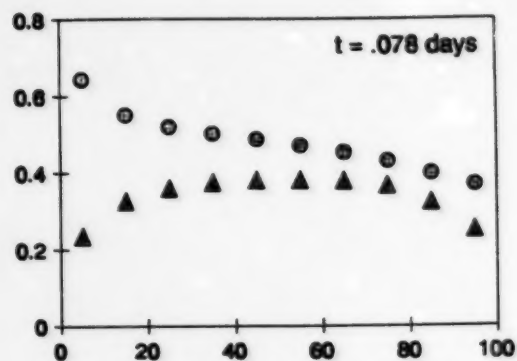
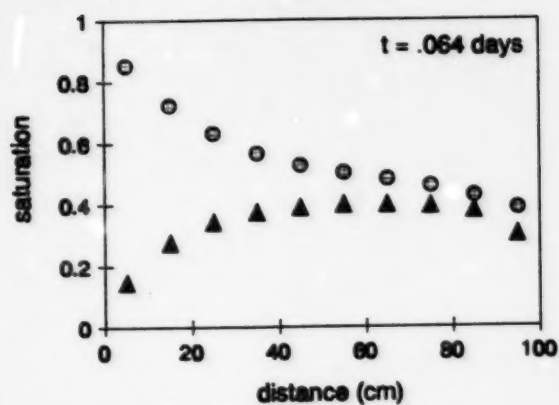


Figure 148: Reservoir pressure plot (Δ), bubble pressure (●). P_c reduced 100 times. B_0 set to 1.0



$P_c = P_c^* 0.01$ $0 < cr < 1$ $b_o \gg 1$ $compr = 0$ **▲ oil ● water**

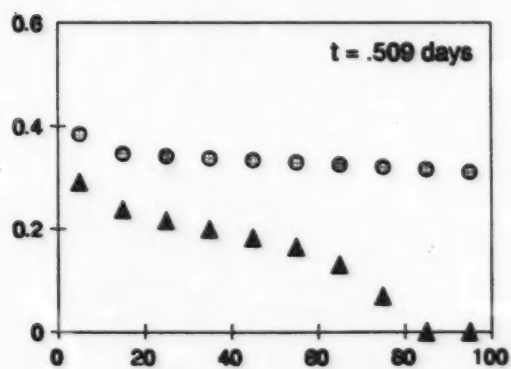
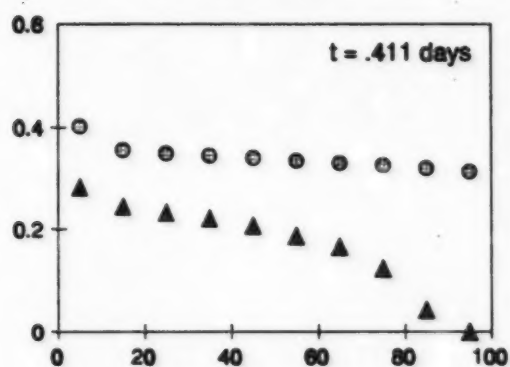
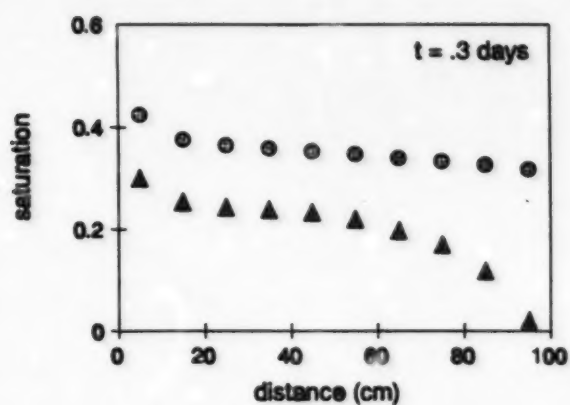
Figure 149: Oil and water saturation plots. P_c values reduced 100 times



$P_c = P_c + 0.01$ $0 < r_s < 1$ $b_o > 1$ $compr = 0$

▲ oil ● water

Figure 149: Oil and water saturation plots. P_c values reduced 100 times



$$P_c = P_c^* \cdot 0.01$$

$$0 < r_s < 1$$

$$b_o \gg 1$$

$$\text{compr} = 0$$

▲ oil ● water

Figure 149: Oil and water saturation plots. P_c values reduced 100 times



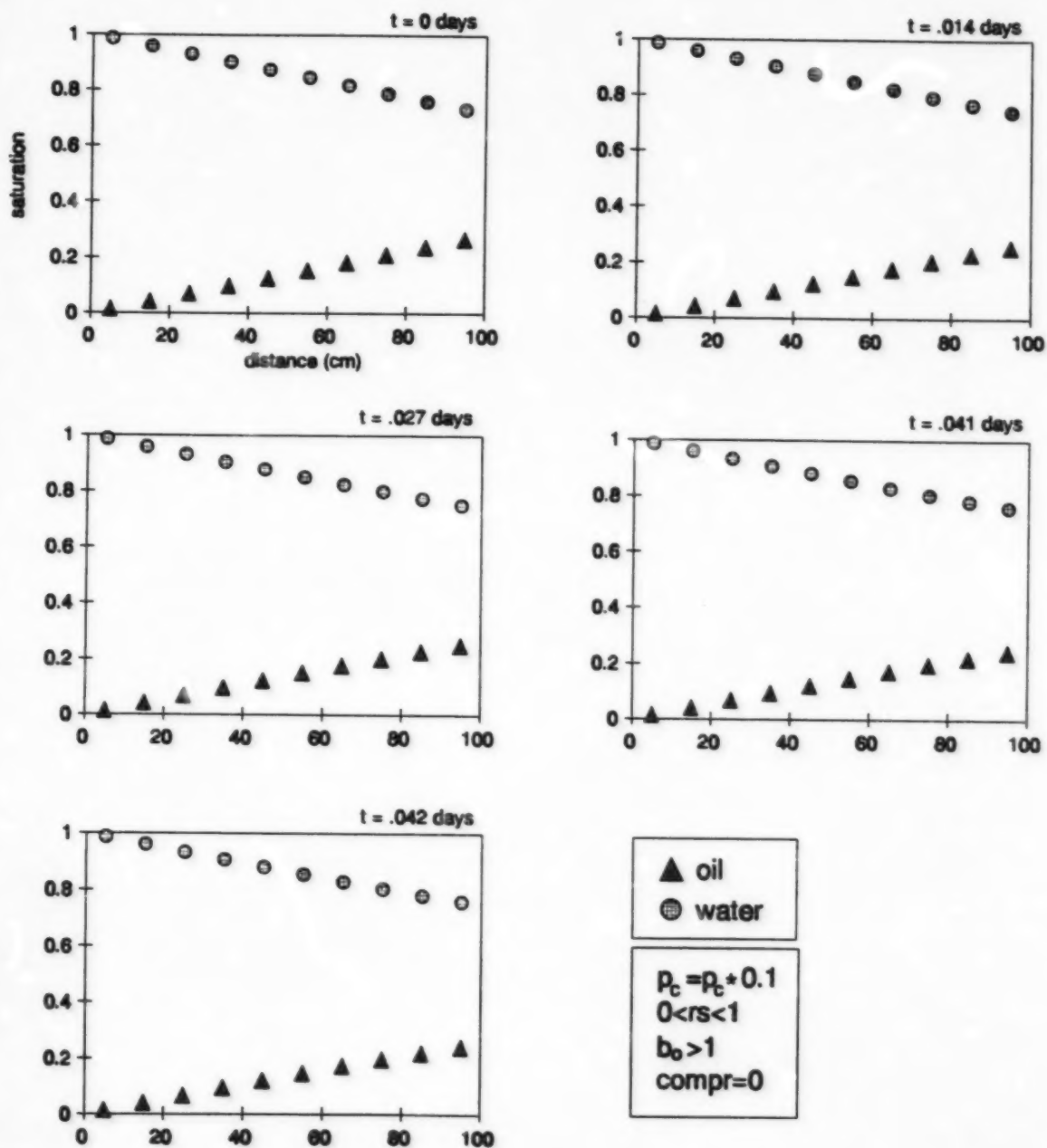
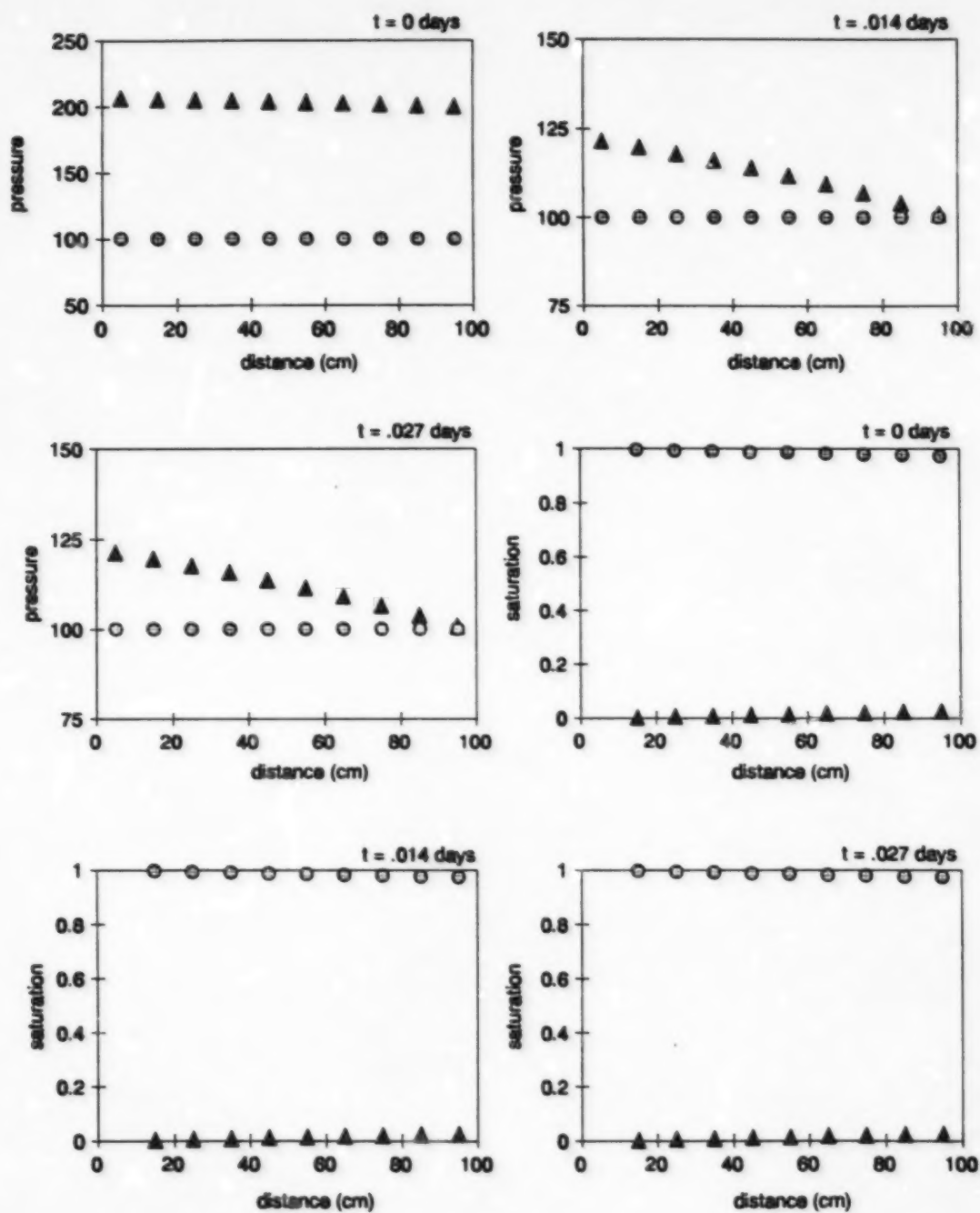


Figure 150: Saturations of oil and water. P_c values reduced 10 times



$$P_c = P_c + 0.1 \quad 0 < r_s < 1 \quad b_o > 1 \quad \text{compr} = 0$$

Figure 151: Plot of reservoir pressure values (▲) and bubble pressure (●)

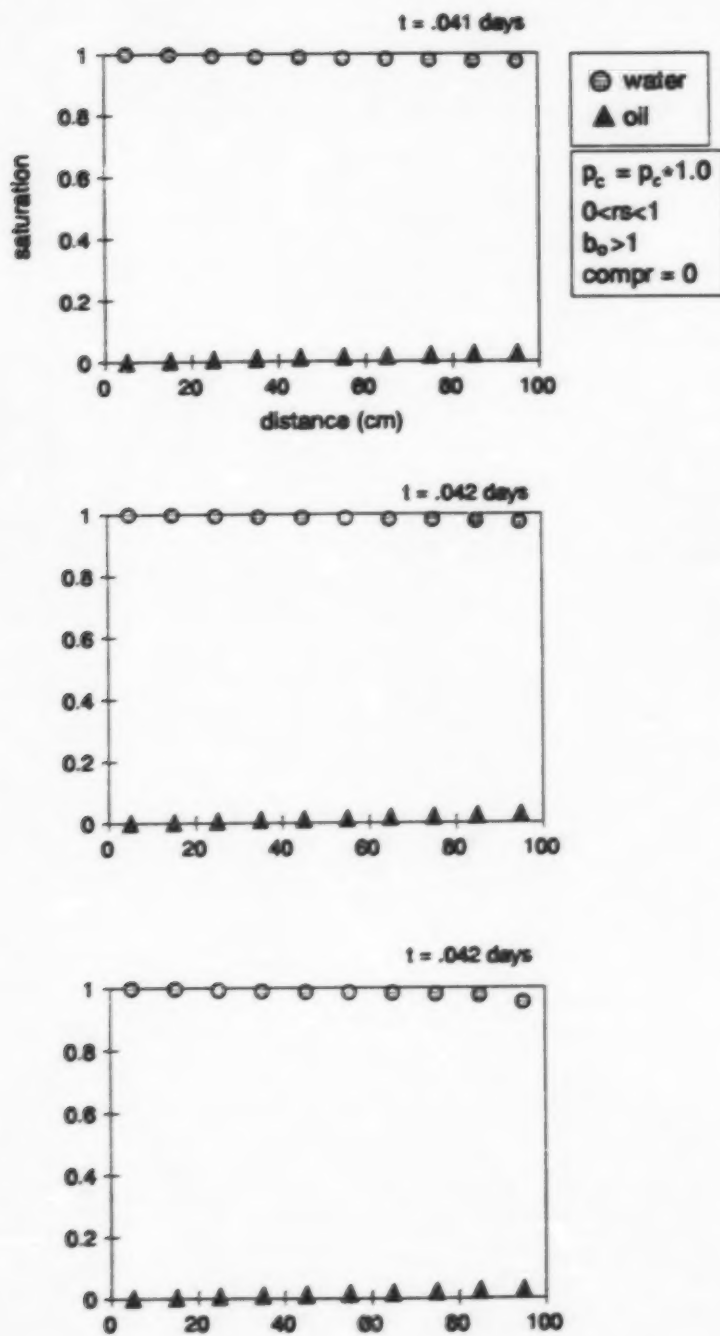
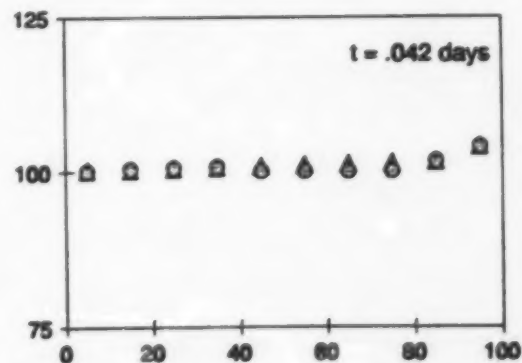
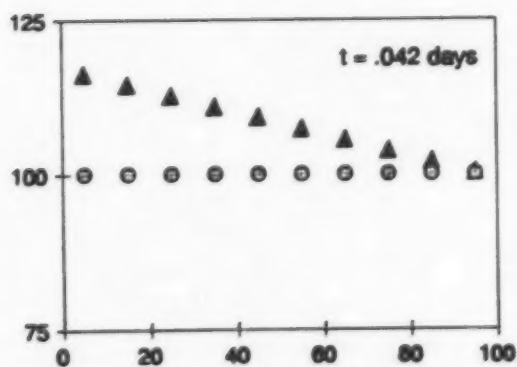
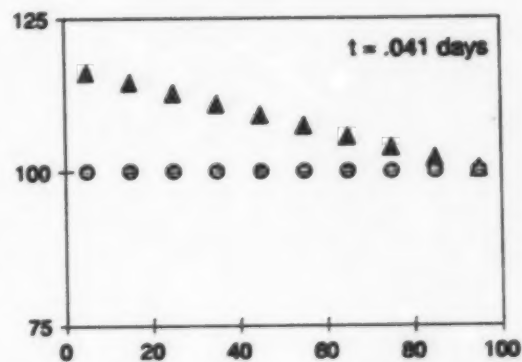
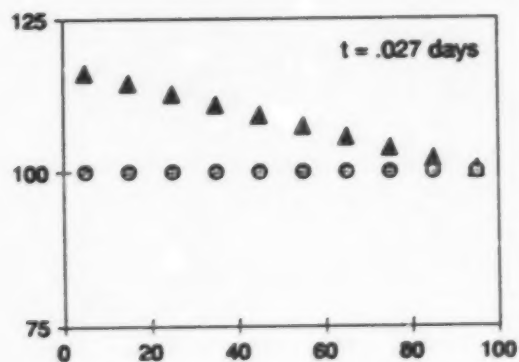
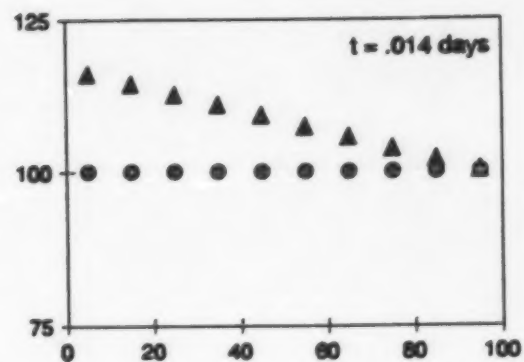
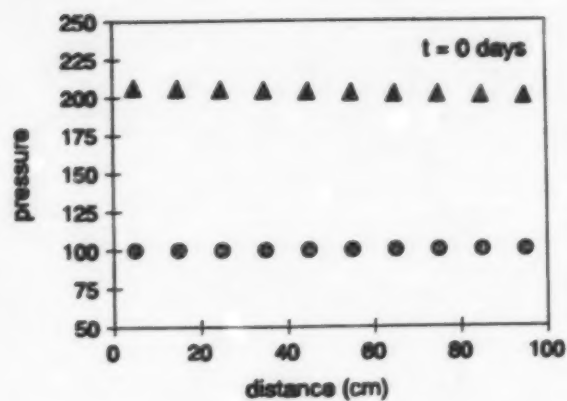
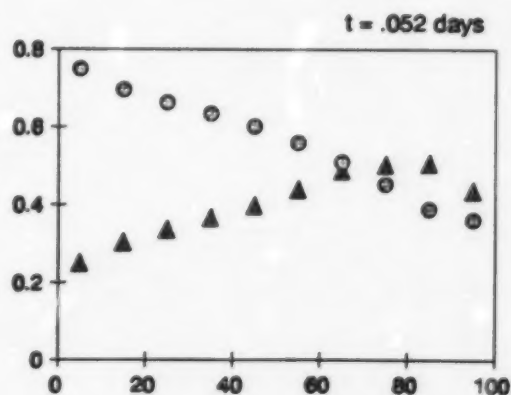
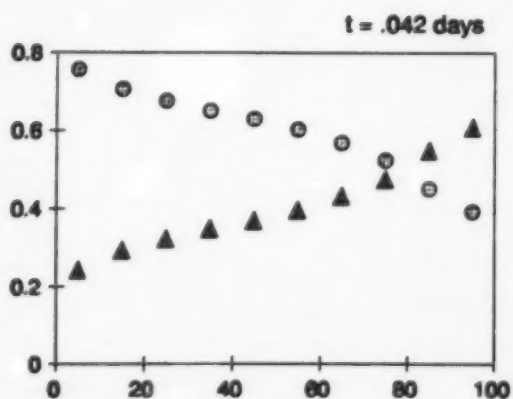
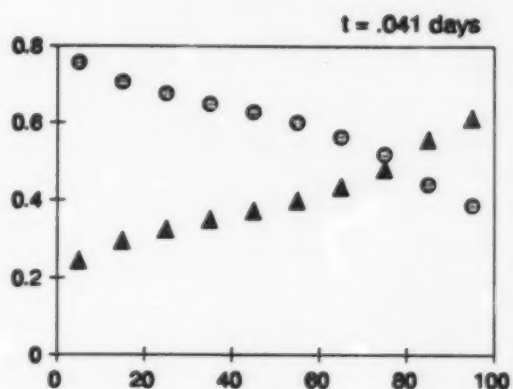
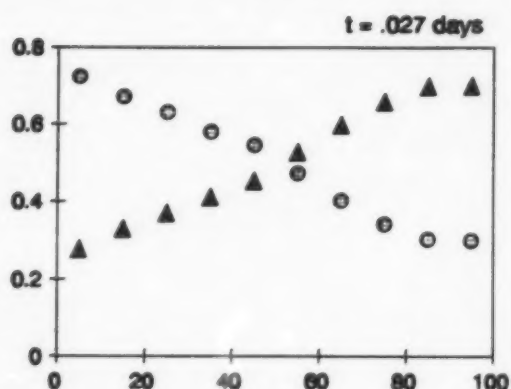
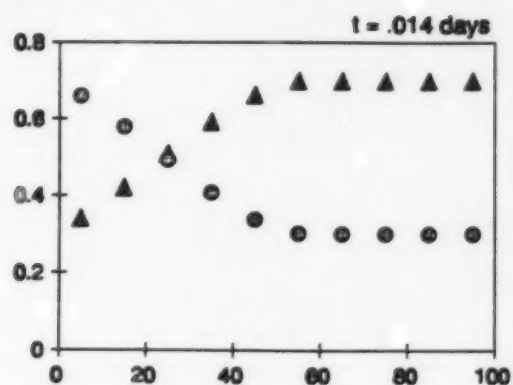
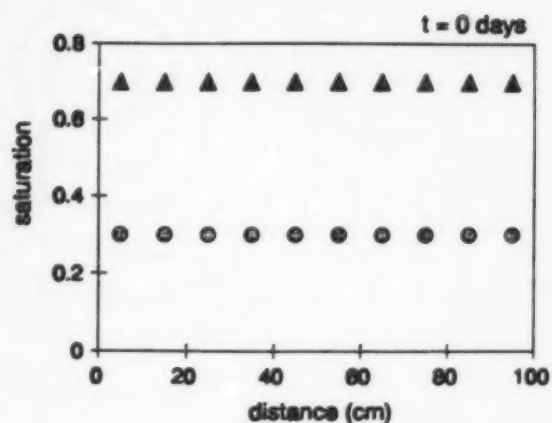


Figure 152: Oil and water saturation profiles. P_c values from Table 19



$$p_c = p_c + 1.0 \quad 0 < r_s < 1 \quad b_o > 1 \quad \text{compr} = 0$$

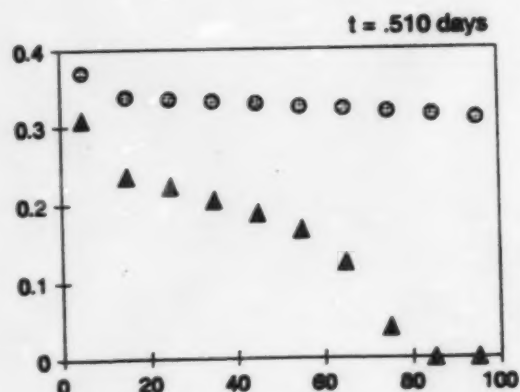
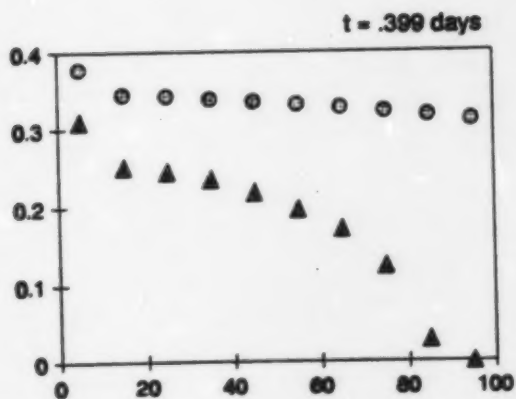
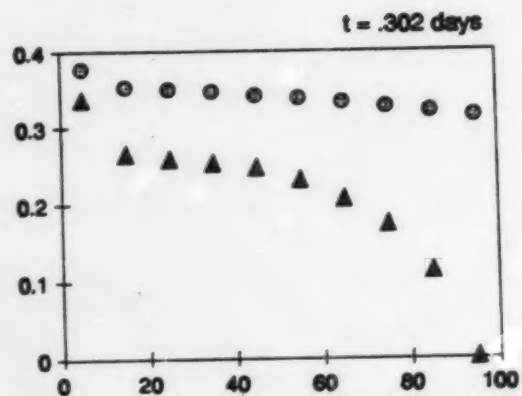
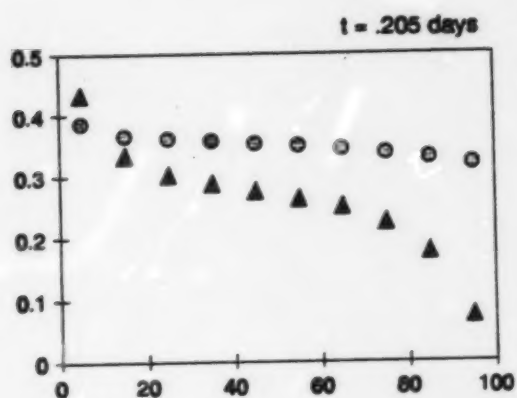
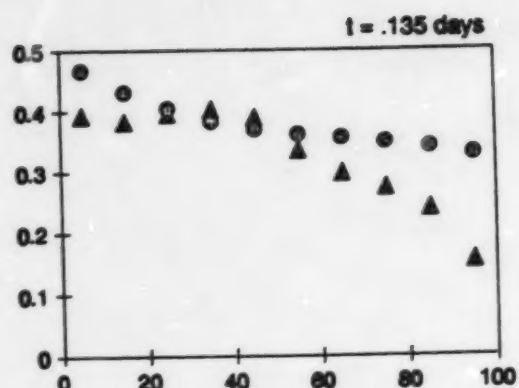
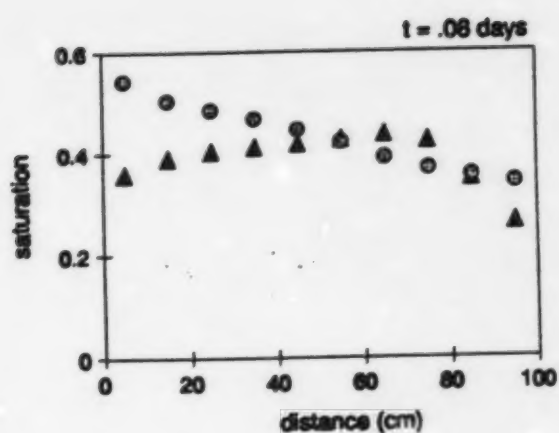
Figure 153: Reservoir pressure curve (A) and bubble pressure curve (●) for the conditions of Figure 152



$p_c = 0.0$ $0 < rs < 1$ $b_o > 1$ $compr = 0$

● water ▲ oil

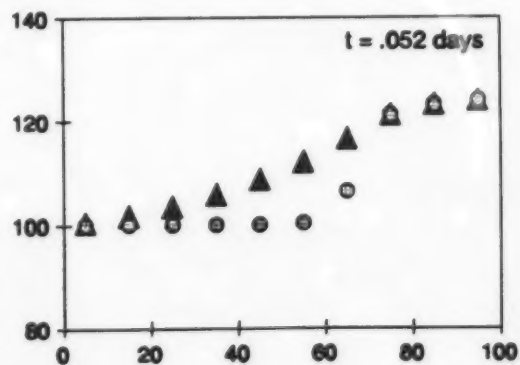
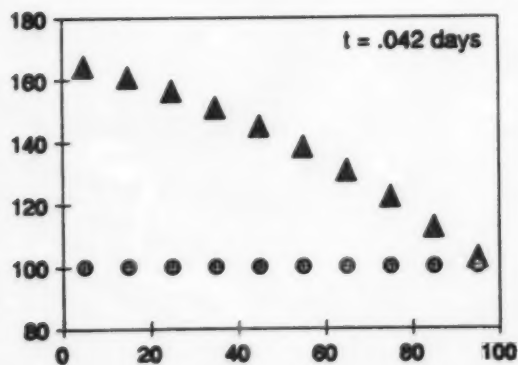
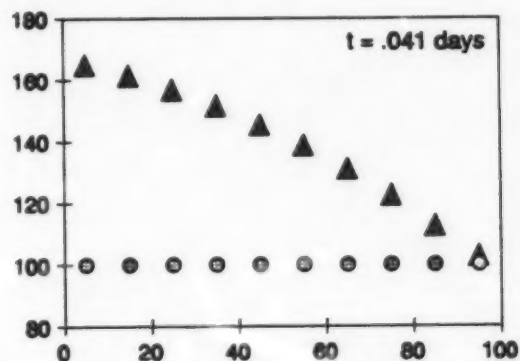
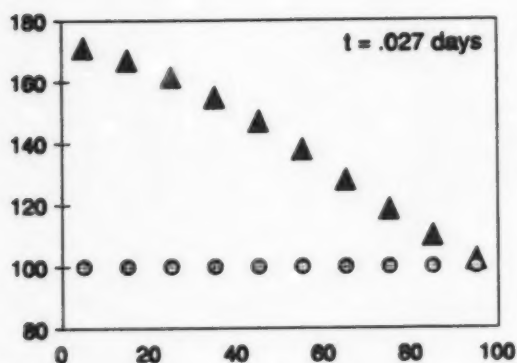
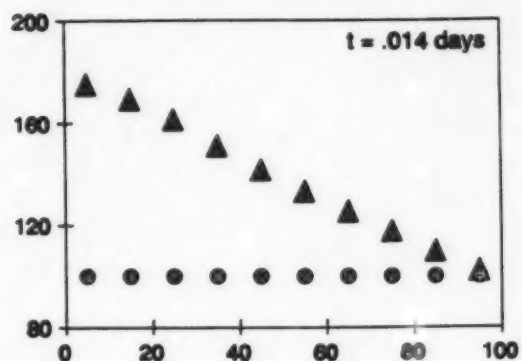
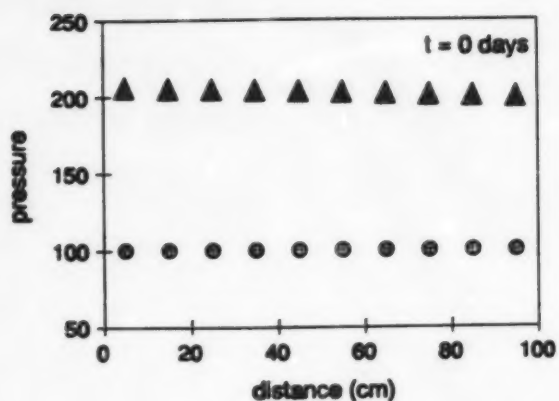
Figure 154: Oil and water saturation profiles. $P_c = 0$



$p_c = 0.0$ $0 < r_s < 1$ $b_o > 1$ $compr = 0$

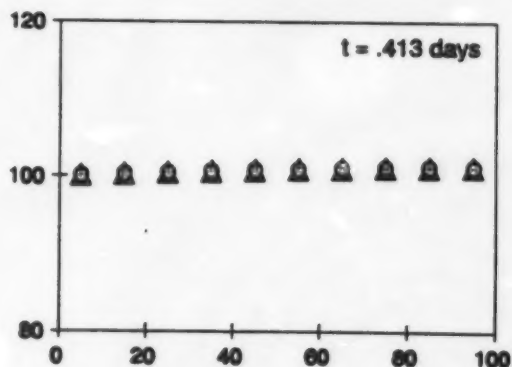
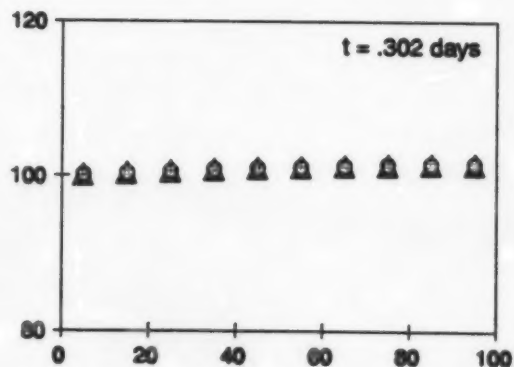
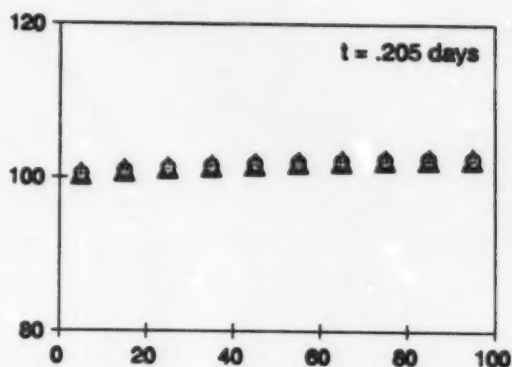
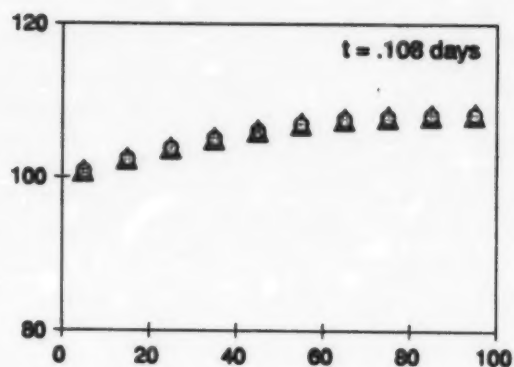
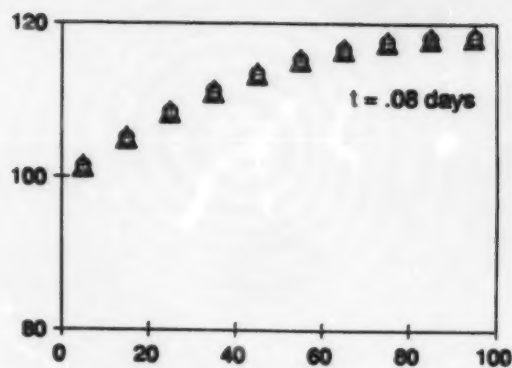
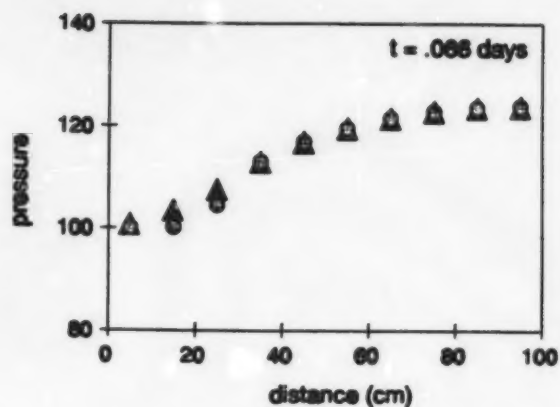
● water ▲ oil

Figure 154: Oil and water saturation profiles. $P_c = 0$



$$p_c = 0.0 \quad 0 < r_s < 1 \quad b_0 > 1 \quad \text{compr} = 0$$

Figure 155: Reservoir (Δ) and bubble (●) pressure curves when $P_c = 0$



$$p_c = 0.0 \quad 0 < rs < 1 \quad b_0 > 1 \quad \text{compr} = 0$$

Figure 155: Reservoir (Δ) and bubble ($\bullet$) pressure curves when $P_c = 0$